4. Resource Development Trends and Emerging Issues

Resource Development Costs and Potential

This section of *Performance Profiles* addresses the costs of finding oil and natural gas, and other resource development issues. While the costs of adding oil and gas reserves (finding costs) do not directly affect the current-year bottom line of the FRS companies (see Chapter 3), they are important in guiding the scale and scope of the companies' current and future resource development strategies. Accordingly, this section also discusses the geographical areas of most importance to the FRS companies' current resource development initiatives. Specifically, this section presents six analyses ("Special Topics") that discuss:

- Variations in regional finding costs
- The impact of mergers and acquisitions on U.S. oil and gas producers
- Increased investment in natural gas
- The status of private investment in Venezuela
- FRS companies in China and Russia
- FRS companies' involvement in Canadian tar sands projects

SPECIAL TOPIC: Reasons for Finding Costs Changes Vary in 2001

Regional Finding Costs Differ in Magnitude and Direction

The FRS companies had large changes in finding costs in each region of the world for the three years ending in 2001 (Table 19). However, these changes ended up largely offsetting each other, resulting in worldwide finding costs remaining essentially unchanged. Finding costs are the costs of adding oil (crude oil and natural gas liquids) and gas (dry natural gas) proven reserves via exploration and development activities.[a] They are measured for oil and gas on a combined basis in units of dollars per barrel of oil equivalent (BOE). Conceptually, finding costs are all the costs incurred (no matter when these costs were incurred or actually recognized on a company's books) in finding any particular proven reserves (not including the purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (except the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[b] Finding costs are generally measured in *Performance Profiles* as a weighted average over a period of three years (to accommodate leads and lags in data reporting), and, if several years of data are presented, they are usually reported in constant dollars (to facilitate comparisons over time).

The regions with the largest changes in finding costs were Canada and the Other Western Hemisphere (increases) and the Other Eastern Hemisphere and the Former Soviet Union and Eastern Europe (decreases) (Table 19). Canada saw the largest absolute and relative increase in finding costs for the three years ending in 2001. Exploration and development expenditures were up 70 percent, led by expenditures for the acquisition of unproved acreage by the FRS companies which soared 250 percent. However, reserve additions through the drill bit increased only 9 percent above their corresponding amount for the previous three years. The increase in expenditures for unproved acreage is in large part due to several mergers, particularly Conoco's purchase of Gulf Canada, Devon Energy's acquisition of Anderson Exploration, Burlington Resources' acquisition of Canadian Hunter Exploration, and Anadarko Petroleum's purchase of Berkley Petroleum. All of these mergers added substantial Canadian unproved acreage to the acquiring company. Conoco is now the fifth-largest oil and gas producer in Canada, while Devon's purchase included 1.5 million net acres in one of Canada's most prospective exploratory region, the far north.[c] Burlington added a portfolio of attractive acreage and exploration and exploitation potential to its holdings, while Anadarko increased its Canadian reserves acreage position from three million to nearly five million net acres.[d] Exxon Mobil (including both companies in previous years) was the largest contributor to drill-bit reserve growth in Canada. The company reports higher spending on major projects in Canada and an increase in the number of net exploration and development wells drilled there from 274 to 509 between 2000 and 2001.[e]

Table 19. Finding Costs by Region for FRS Companies, 1998-2000 and 1999-2001
(Dollars per Barrel of Oil Equivalent)

Region	1998-2000	1999-2001	Percent Change
United States			
Onshore	4.90	6.01	22.8
Offshore	9.99	6.99	-30.1
Total United States	6.47	6.39	-1.3
Foreign			
Canada	6.84	10.70	56.5
OECD Europe	7.43	5.51	-25.9
Former Soviet Union and Eastern Europe	7.01	3.26	-53.5
Africa	2.78	3.68	32.3
Middle East	5.61	7.66	36.7
Other Eastern Hemisphere	7.49	4.07	-45.7
Other Western Hemisphere	4.37	6.22	42.5
Total Foreign	5.26	5.25	-0.1
Worldwide	5.81	5.78	-0.6

Notes: The above figures are 3-year weighted averages of exploration and development expenditures (current dollars), excluding expenditures for proven acreage, divided by reserve additions, excluding net purchases of reserves. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The Other Western Hemisphere (largely South America) also saw a large proportional increase in finding costs for the three years ending in 2001. In this case, the primary cause was a large decline in total reserves found by the drill bit. In fact, in 2001, some FRS companies had large negative revisions of previous reserves estimates while others had much smaller additions to reserves.

The Former Soviet Union and Eastern Europe had the largest absolute and relative decrease in finding costs for the 1999 to 2001 period. Two developments pushed down the finding costs in this region, a notable increase in the quantity of reserves added through the drill bit and a large decline in expenditures for unproven acreage. BP[f] and Unocal both have substantial exploration and development activities in Azerbaijan, located on the Caspian Sea. BP is the operator and holds major interests in the Azeri-Chirag-Gunashli oil fields and the Shah Deniz natural gas field.[g] Unocal has a 10-percent working interest in the Azeri-Chirag-Gunashli fields.[h] The decline in expenditures for unproven acreage was to a large extent the result of the exclusion of Phillips Petroleum's (now part of Conoco Phillips) significant acquisition expenditures for leases and interests in Kazakhstan, also on the Caspian, in 1998 which are not included in the 1991 – 2001 finding costs.[i]

The Other Eastern Hemisphere also had a large decline in finding costs for the 1999 to 2001 period, even with a notable increase in development expenditures, because reserves added through the drill bit more than doubled. ChevronTexaco has development projects underway in Indonesia, Papua New Guinea, the Philippines, and China.[j] In addition to ChevronTexaco, several FRS companies had substantial operations for the three years ending in 2001 in the Other Eastern Hemisphere, including Unocal, Conoco, and Shell Oil.

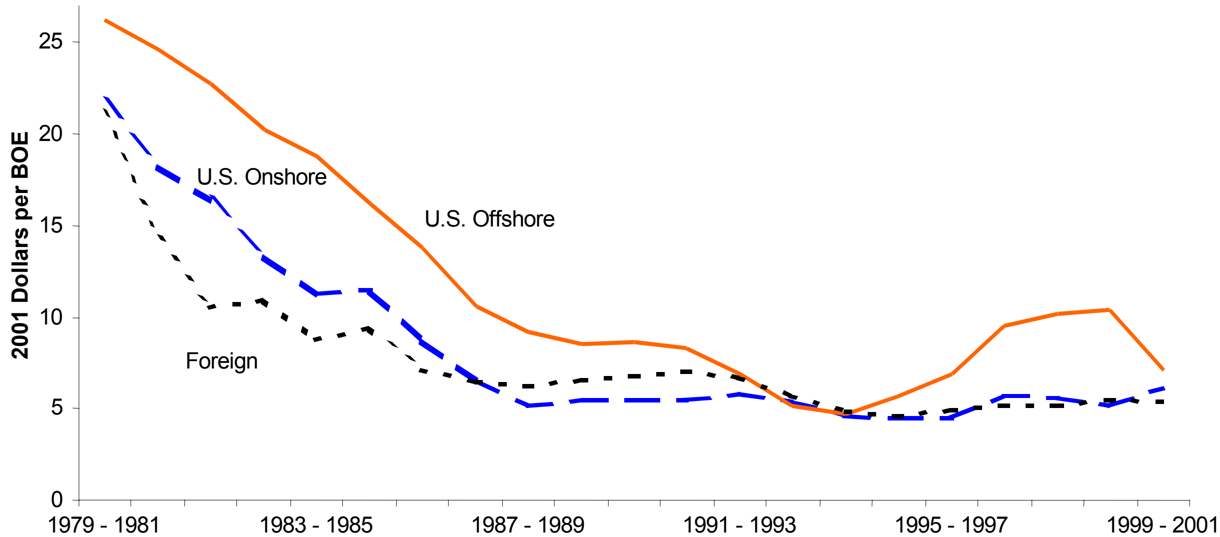
Offshore Finding Costs Run Counter to Recent Trend

Until 2001, finding costs in the U.S. Offshore (largely Gulf of Mexico) region had been rising steadily in recent years (Figure 26). They were the highest of any FRS region for the three years ending in 2000 (Table 19). However, offshore finding costs for the three years ending in 2001 erased more than half of the increase from the preceding five-year rise and brought offshore finding costs closer to their long-term trend. A combination of a substantial increase in reserve additions through the drill bit and, to a lesser extent, a fall in expenditures for unproved acreage were the driving forces behind this decline. BP is the largest leaseholder in the Gulf and has interests in nine of the ten largest developments there.[k] In addition to a discovery at Blind Faith, BP booked 30 million barrels of oil equivalent gross reserves in two major prospects, the Pompano Subsalt and MC29. Some of BP's other projects, such as the Nile, King, and King West subsea developments and the Troika and Mars fields, also have exploration and development activities ongoing. Expenditures for unproved acreage declined largely because Sonat's (merged into El Paso Energy in 1999) purchase of Zilkha Energy in 1998 was dropped from the 1991 - 2001 calculation.

While foreign finding costs remained essentially flat, U.S. onshore finding costs rose 23 percent for the three years ending in 2001 (Table 19). This increase was largely brought about by a swell in development spending in the 1999 to 2001 period. In Alaska, BP is carrying out extensive development programs, especially at Prudhoe Bay and its satellite fields, to mitigate natural production declines.[l] BP is conducting development drilling at the Borealis and Northwest Eileen fields in Alaska, where 19 new wells were drilled in 2001. The company is also pursuing development projects in the lower-48 States. A highlight of BP's development spending there is a drilling program in the Overthrust Belt and Greater Green River Basin areas of Southern Wyoming, which broke several company drilling records in 2001. In addition, Phillips Petroleum acquired Atlantic Richfield's Alaskan oil and gas assets in 2000, and, like BP, is conducting extensive development programs in Alaska, including satellite and infield development at Prudhoe Bay in the Kuparak area.[m]

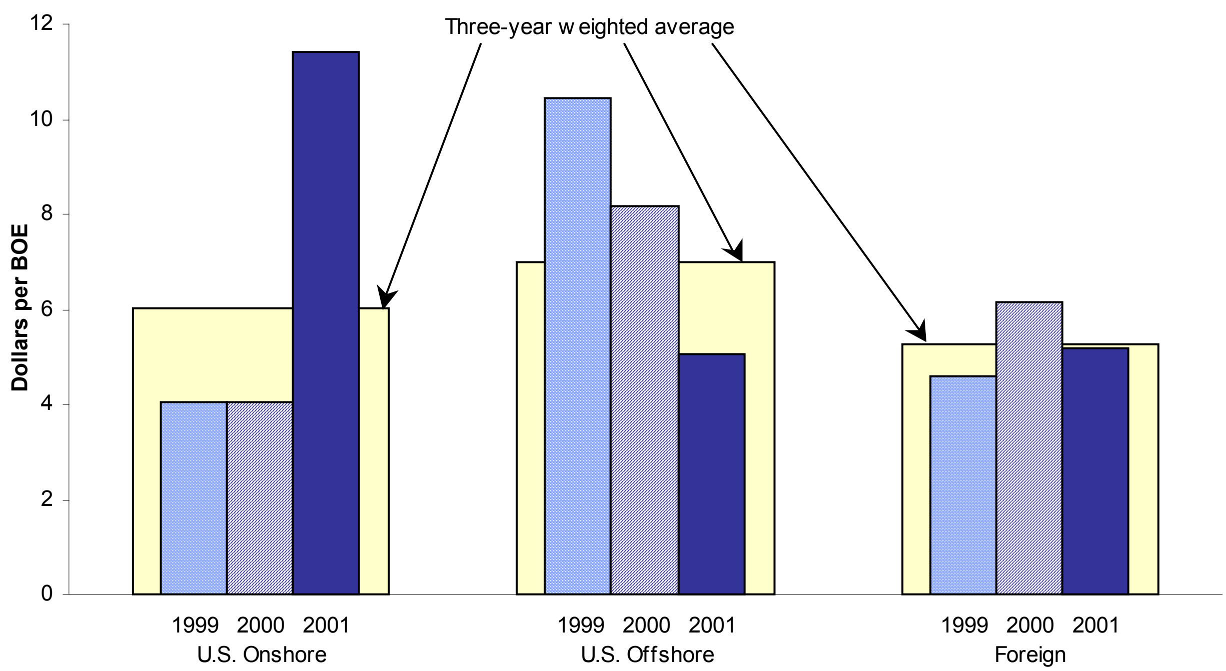
One-year finding costs can provide additional information on near-term changes in three-year finding costs. Although one-year finding costs vary more than three-year costs, they can also pick up trends sooner than three-year costs. In 1998, one-year finding costs in the U.S. Offshore region surged to their highest level since the 1980's but have been declining since then, prefacing the decline in three-year costs for the 1999 to 2001 period (Figure 27). One-year finding costs for the U.S. Onshore region reached their highest level since the 1980's in 2001, leading to a sharp increase in three-year costs. Foreign one-year finding costs have been relatively stable in recent years.

Figure 26. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted Average Finding Costs for FRS Companies, 1979-1981 to 1999-2001



Note: Finding costs are weighted averages of the annual finding costs for the three years specified. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages. Values tend to be associated with the middle year of the 3-year average and plotted to reflect that. That is, the 1979 to 1981 average is plotted as though it is a value for 1980.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 27. Finding Costs for FRS Companies, Annual and Three-Year Weighted Average, 1999-2001



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

[a]Alternatively, finding costs are the exploration and development costs of replacing reserves removed through production.
[b]One inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not usually correspond exactly with each other. Expenditures are usually recognized in the period that that the payment actually occurred. Proven reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must occur in the same time period (oil and gas wells are often operated for a long time), so that some expenditures may not be recognized in the same time period that their corresponding reserves are recognized. One way to moderate this limitation is to increase the length of the time period over which finding costs are measured, allowing reserve additions and exploration and development expenditures to match up more closely. However, the longer the time period over which finding costs are measured, the more out of date they become, because they include older and older expenditures and reserves, and costs and technology are constantly changing. The only way to solve the correspondence problem would be to calculate an average finding cost for all of the oil and gas produced by a well after it is permanently shut in. But then many costs included would be far out of date.
[c]Conoco Inc., 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 6, and Devon Energy, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 23.
[d]Burlington Resources, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 1, and Anadarko Petroleum, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 14.
[e]Exxon Mobil Corporation, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, pp. 10 and 28, and 2000 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 10
[f]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[g]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 32-33.
[h]Unocal Corporation, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 15.
[i]Phillips Petroleum Company, *1998 Annual Report*, http://www.phillips66.com/annual98/1exploration.htm, November 3, 2002.
[j]ChevronTexaco Corporation, *2001 Supplement to the Annual Report*, pp. 22-26.
[k]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 19 and 27.
[l]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 27-29.
[m]Phillips Petroleum Company, *2001 Annual Report*, p. 11.

SPECIAL TOPIC: U.S. Oil and Gas Producers -- Mergers and Acquisitions Create Turnover, But Concentration Not Altered

Half of the companies constituting the top-20 oil and top-20 natural gas producers in the United States in 1992 merged or were acquired by the end of 2001.[a] These deals freed up slots on the top-20 lists for the entrance of several new companies. However, even after all of these mergers and acquisitions, the concentration of the industry changed little over the period, with the top-20 companies continuing to produce about half of the total output of oil and gas in the United States.

The top-three producers of oil and of natural gas in the United States, BP (BP America), ChevronTexaco, and Exxon Mobil, have all been involved in major mergers in the past few years, with British Petroleum and BP Amoco (BP's[b] predecessors) acquiring Amoco and Atlantic Richfield, respectively, and the mergers of Chevron with Texaco and Exxon with Mobil. These combinations involved six of the top-seven 1992 producers of oil and of natural gas in 1992 (Tables 20 and 21). Other major combinations among members of the 1992 group were Anadarko Petroleum's acquisition of Union Pacific Resources, Kerr-McGee's acquisition of Oryx Energy, and Devon Energy's purchase of PennzEnergy (earlier spun off from Pennzoil) and Santa Fe Snyder Energy Resources (the outcome of an earlier merger between Santa Fe Energy Resources and Snyder Oil).[c]

Table 20. U.S. Oil Production of 20 Largest Producers, 1992 and 2001
(Million Barrels)

1992			2001		
Company	Production	Percent of U.S. Total	Company	Production	Percent of U.S. Total
British Petroleum	251.8	7.8	BP	243.0	8.7
Atlantic Richfield	242.0	7.5	ChevronTexaco	224.0	8.0
Exxon	216.0	6.7	Exxon Mobil	210.0	7.5
Royal/Dutch Shell	163.0	5.1	Phillips Petroleum	154.0	5.5
Chevron	158.0	4.9	Royal/Dutch Shell	108.0	3.9
Texaco	158.0	4.9	Occidental Petroleum	78.0	2.8
Mobil	114.0	3.5	Anadarko Petroleum	48.0	1.7
Amoco	107.0	3.3	Marathon Oil	46.0	1.6
Phillips Petroleum	50.0	1.6	Devon Energy	32.0	1.1
Unocal	47.0	1.5	Unocal	29.0	1.0
USX-Marathon	42.0	1.3	Burlington Resources	28.7	1.0
Conoco	41.0	1.3	Kerr-McGee	28.0	1.0
Union Pacific Resources	31.8	1.0	Amerada Hess	28.0	1.0
Oryx Energy	30.0	0.9	Conoco	27.0	1.0
Amerada Hess	27.0	0.8	Apache	24.2	0.9
Occidental Petroleum	22.0	0.7	Mitchell Energy & Development	21.8	0.8
Santa Fe Energy Resources	21.4	0.7	Pioneer Natural Resources	15.9	0.6
Mitchell Energy & Development	19.2	0.6	Nuevo Energy	14.5	0.5
Burlington Resources	15.4	0.5	El Paso	13.8	0.5
Pennzoil	15.0	0.5	Ocean Energy	10.2	0.4
Top-20 Total	1,771.6	55.0	**Top-20 Total**	1,384.1	49.3
U.S. Total	3,219.0	100.0	**U.S. Total**	2,805.0	100.0

Concentration Measures

Herfindahl-Hirschman Index (20 firm)	**272**	**Herfindahl-Hirschman Index (20 firm)**	**262**
Concentration Ratio (4 firm)	**27**	**Concentration Ratio (4 firm)**	**30**
Concentration Ratio (8 firm)	**44**	**Concentration Ratio (8 firm)**	**40**
Concentration Ratio (20 firm)	**55**	**Concentration Ratio (20 firm)**	**49**

Sources: *Oil&Gas Journal,* September 20, 1993 and October 1, 2001, BP and Royal/Dutch Shell, 2001 Reports to the Securities and Exchange Commission on Form 20-F, Occidental Petroleum, 2001 Report to the Securities and Exchange Commission on Form 10-K, Energy Information Administration, "Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report," DOE/EIA-0216(2001)Advance Summary, September 2002, Table 1.

Other transactions and corporate restructurings resulted in several newcomers to the top-20 lists. El Paso, which was initially spun off from Burlington Resources as a natural gas transmission company, acquired two natural gas producers, Sonat and then Coastal, on its way to becoming the sixth largest natural gas producer in the United States. Pioneer Natural Resources arose from a merger between Parker & Parsley Petroleum and MESA, and Ocean Energy merged with Seagull Energy and United Meridian to join the top-20 group. In addition, Dominion Resources, formerly an electric and gas utility, purchased Consolidated Natural Gas to solidify its entry in natural gas exploration and production.[d] Nuevo Energy made a large purchase of oil and gas reserves in California and Apache made numerous smaller purchases of reserves to boost them into the top-20 producers. Two companies that were restructured also made the 2001 lists. EOG Resources was spun off from Enron and USX separated its two divisions, Marathon and United States Steel, and re-established them as independent companies.

Table 21. U.S. Natural Gas Production of 20 Largest Producers, 1992 and 2001
(Billion Cubic Feet)

1992			2001		
Company	**Production**	**Percent of U.S. Total**	**Company**	**Production**	**Percent of U.S. Total**
Chevron	847	4.9	BP	1,358	6.9
Amoco	845	4.8	Exxon Mobil	1,114	5.6
Texaco	672	3.9	ChevronTexaco	988	5.0
Exxon	649	3.7	Royal/Dutch Shell	581	2.9
Mobil	600	3.4	Anadarko Petroleum	573	2.9
Royal/Dutch Shell	532	3.1	El Paso	552	2.8
Atlantic Richfield	440	2.5	Burlington Resources	409	2.1
Unocal	359	2.1	Phillips Petroleum	402	2.0
Phillips Petroleum	350	2.0	Devon Energy	376	1.9
Burlington Resources	300	1.7	Unocal	371	1.9
Conoco	279	1.6	Conoco	291	1.5
Occidental Petroleum	226	1.3	Marathon Oil	289	1.5
USX-Marathon	224	1.3	EOG Resources	252	1.3
Amerada Hess	220	1.3	Dominion Resources	230	1.2
Oryx Energy	214	1.2	Apache	225	1.1
Union Pacific Resources	211	1.2	Occidental Petroleum	223	1.1
Enron	200	1.1	Kerr-McGee	195	1.0
Pennzoil	161	0.9	Amerada Hess	155	0.8
Anadarko Petroleum	144	0.8	XTO Energy	152	0.8
Consolidated Natural Gas	128	0.7	Ocean Energy	152	0.8
Top-20 Total	7,600.5	43.6	**Top-20 Total**	8,888	44.9
U.S. Total	17,423	100.0	**U.S. Total**	19,779	100.0

Concentration Measures

Herfindahl-Hirschman Index (20 firm)	**129**	**Herfindahl-Hirschman Index (20 firm)**	**157**
Concentration Ratio (4 firm)	**17**	**Concentration Ratio (4 firm)**	**20**
Concentration Ratio (8 firm)	**28**	**Concentration Ratio (8 firm)**	**30**
Concentration Ratio (20 firm)	**44**	**Concentration Ratio (20 firm)**	**45**

Sources: *Oil&Gas Journal,* September 20, 1993 and October 1, 2001, BP and Royal/Dutch Shell, 2001 Reports to the Securities and Exchange Commission on Form 20-F, Occidental Petroleum, 2001 Report to the Securities and Exchange Commission on Form 10-K, Energy Information Administration, "Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report," DOE/EIA-0216(2001)Advance Summary, September 2002.

Despite all of these mergers and acquisitions, concentration in U.S. oil production and natural gas production changed little between 1992 and 2001 (Tables 20 and 21). Both industries remained unconcentrated, and overall concentration in oil production actually declined slightly, with the Herfindahl-Hirschman Index falling from 272 in 1992 to 262 in 2001.[e] The production of oil and of natural gas did become more concentrated at the top, with the 4-firm concentration ratios for both groups increasing 3 percentage points. In contrast, the 8-firm and 20-firm concentration ratios fell for oil, and, while all concentration ratios were slightly higher for natural gas production in 2001, the 8-firm and 20-firm ratios exceeded the 4-firm ratio less than in 1992, indicating less concentration in natural gas production as well below the top companies.[f]

The companies that were on the top-20 list of producers in 2001 can be divided into two groups, survivors and entrants. Survivors are companies that were on the top-20 list in 1992 or are composed of companies that were on the list. Entrants are companies that were not in the top-20 list in 1992, although they may have acquired or merged with companies that were on the list in the earlier year. When the companies are divided into these two groups, contrasts between them become apparent. For both oil production and natural gas, entrants more than replaced their production during 1992 through 2001 with reserves added through the drill bit, while survivors did not (Table 22).[g] However, the groups are not consistent in the manner in which they added reserves through the drill bit. Entrants use improved recovery techniques for a higher proportion of their natural gas reserves additions than survivors, while survivors use improved recovery for a higher proportion of their oil reserves additions through the drill bit.

Table 22. Top-20 Producers' Reserve Additions Through Exploration and Development, 1992-2001
(Percent)

	Survivors			Entrants		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Extensions and Discoveries	59	86	72	68	76	73
Improved Recovery Techniques	25	2	14	9	17	14
Revisions to Estimates	15	12	14	24	7	13
Total	100	100	100	100	100	100
Production Replacement Rate (Excluding Purchases and Sales)	94	88	91	142	101	112

Note: Sum of components may not add to total due to independent rounding.
Source: Derived from data provided by John S. Herold, Inc.

[a]Two mergers since the end of 2001 have further altered the lists for 2002. Devon Energy acquired Mitchell Energy & Development and Conoco and Phillips Petroleum merged.
[b]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
c[b]Other notable mergers in which one of the top-20 companies was involved included Kerr-McGee's acquisition of HS Resources, Burlington Resources' purchase of Louisiana Land & Exploration, Occidental Petroleum's acquisition of Altura Energy, and Unocal's purchase of Titan Exploration.
[d]Dominion Resources also purchased Louis Dreyfus Natural Gas in 2001.
[e]For a brief introduction to concentration measures, see "Top Oil Corporations Nearly Double Share of World Oil Production" in Chapter 3.
[f]In oil production, concentration in 2001 compared to 1992 began to decrease with the fifth company on the list, in natural gas, where concentration overall increased slightly, it nonetheless was less beginning with the fourth company on the list.
[g]These results are based on calculations using reserves and production data provided by John S. Herold, Inc.

SPECIAL TOPIC: Upstream Investment Focuses on Natural Gas, Large Projects

In the U.S. oil and gas industry of just a few decades ago, the basic strategy for growth was to find good acreage in the United States on which to drill for oil. Natural gas was widely viewed as less profitable than oil and, because of nationalizations and wars in the Middle East, drilling overseas was widely viewed as overly risky given international politics. Since then, almost everything has changed.

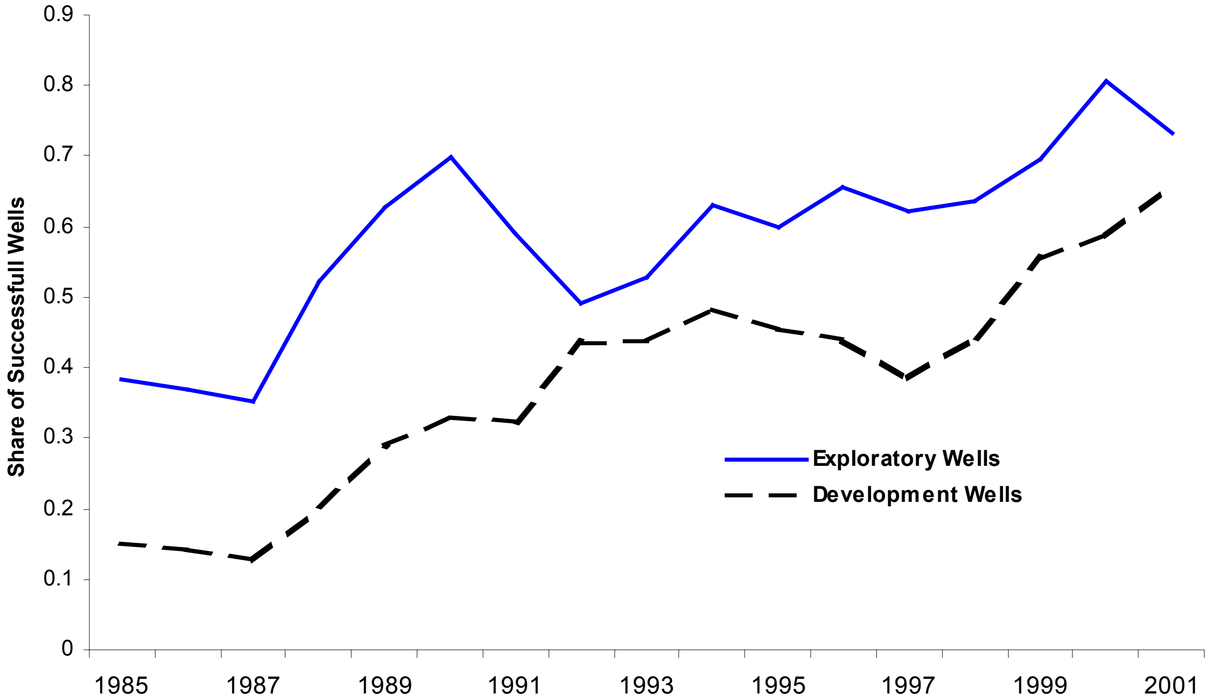
Over the period 1990 to 2001, worldwide demand for natural gas increased by 22 percent while oil demand grew a more modest 14 percent.[a] In addition, the Energy Information Administration produced evidence that suggests that the profit margins for gas were higher than for oil throughout most of the 1980's and 1990's.[b] This combination of higher unit profits and growing demand has led to an increased focus on natural gas as a means to achieve upstream profitability and growth. This change is evident in the natural gas well share of worldwide well completions by the FRS companies, which has been increasing since the mid-1980's (Figure 28).

In addition to an increased emphasis in natural gas, the FRS companies have shifted their operations overseas in search of new oil and gas reserves. One reason for this is that oil and gas historically tend to be cheaper to find overseas than in the United States (Figure 26). This can be seen in the substantially increased share of the FRS companies' exploration and development expenditures accounted for by activities outside the United States during the 1980's and into the early 1990's. In the 1990's, U.S. and overall foreign finding costs have roughly converged, resulting in a 50-50 split of exploration and development expenditures between the United States and overseas in recent years (Figure 29).

In addition, there is increasing recognition that, as with financial portfolios, there tends to be an inherent tradeoff between the expected returns of oil and gas projects and their riskiness.[c] While projects such as deepwater Gulf of Mexico oil and gas, liquefied natural gas (LNG) in Indonesia, oil in West Africa, and oil and gas in the Caspian may have considerably higher expected returns than conventional oil and gas in the lower 48 States, they also have substantially more risk. Firms can therefore be expected to seek to assemble a portfolio of projects, some of which are individually quite risky, but taken as a group have much less risk. This can maximize long-run shareholder value while keeping the portfolio's overall level of risk within acceptable limits.

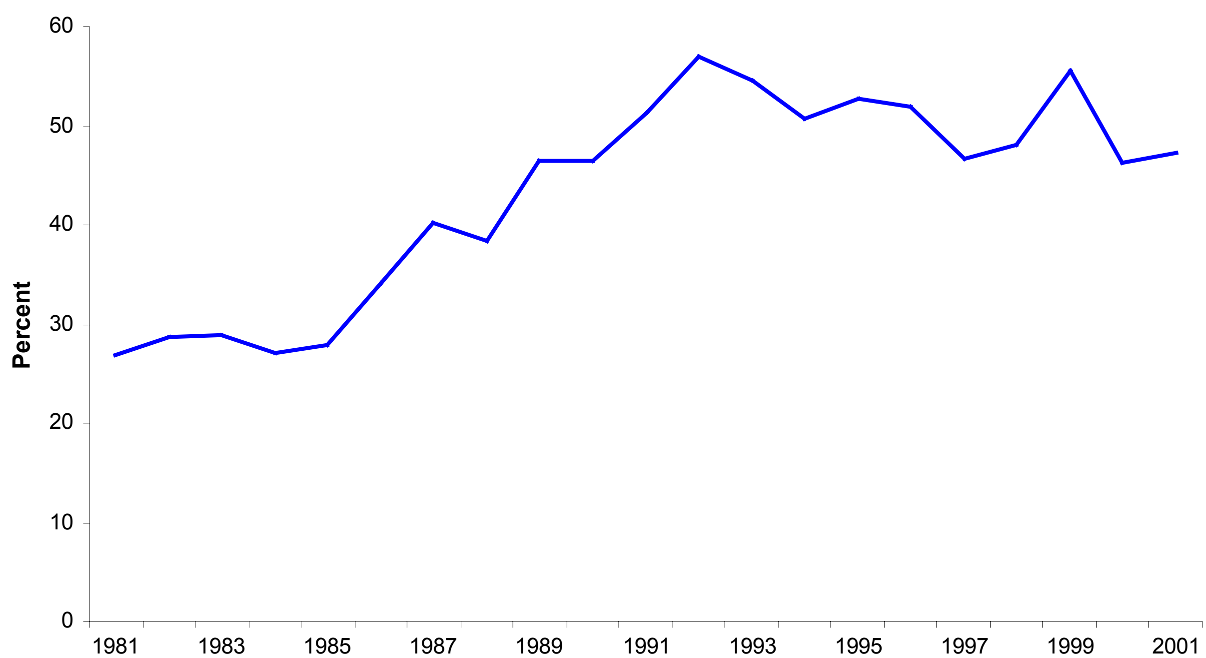
Effective application of this portfolio approach to upstream investments requires that a firm have a sufficiently large number of diverse projects in its portfolio. Over the next decade much of the growth in the world's energy supply likely will come from a relatively small number of large projects in a number of different countries. Natural gas projects under consideration include operations in Trinidad, Algeria, Australia, and the deepwater Gulf of Mexico. Potential oil projects are located in Canada (oil sands), the offshore of West Africa, the Caspian Sea region, and Russia. The common denominator across these projects is their massive scale. For instance, a deepwater prospect in the Gulf of Mexico or in the offshore of West Africa can easily cost a billion dollars, substantially more than a typical project of a decade ago.

Figure 28. The Natural Gas Share of FRS Successful Exploratory and Developmental Oil and Gas Well Completions, 1985-2001.



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Figure 29. Foreign Expenditures Share of Worldwide Exploration and Development Expenditures by FRS Companies, 1981-2001



Note: Excludes expenditures on proved acreage.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Following are examples of projects that are being considered by the FRS companies.

Advanced Technology in the Deepwater: One firm that has embraced the advanced technology strategy is BP[d], which recently announced that it plans to invest $15 billion by 2010 in the Gulf of Mexico to develop six large fields, including the requisite undersea pipeline system. The fields to be developed include Thunder Horse, which is estimated to contain over one billion barrels of oil equivalent (boe), making it the largest find to date in the region. While BP's current daily production of 340,000 boe makes it the second largest producer in the Gulf, the company is hopeful that its investment program will allow it to double production there by 2007.[e] The risks posed by this strategy include the substantial challenges of deploying deepwater exploration, development, and production technologies without endangering either the environment or the bottom line.

Nonconventional Gas: Environmental concerns are expected to substantially increase the future demand for natural gas. However, there is some question whether this projected demand increase can be sustained by conventional natural gas supply at current prices. This has led producers to reconsider the role of nonconventional gas in their exploration and development portfolios. Drilling for nonconventional gas such as coalbed methane before 1993 was motivated largely by production tax credits that were in excess of 50 percent of the market price.[f] With the expiration of the credits for new wells, drilling for coalbed methane is no longer subsidized. Because of the relative maturity of the conventional onshore resource base, the technological advances in nonconventional gas production over the last decade, and the experience gained when the credits were in effect, nonconventional gas drilling in 2000, that latest year for which data are available, was 21 percent higher than in 1992, the last year that newly drilled nonconventional wells were eligible for the tax credit.[g]

Nonconventional Oil: While there is some controversy about how much conventional oil remains to be discovered and produced, there is little question that the world is endowed with hundreds of billions of barrels of unexploited heavy crude oils such as the bitumen deposits in Canada and Venezuela's Orinoco Belt. The accepted wisdom has long been that these crudes were too expensive to produce at current prices. Technological advances, especially those in horizontal drilling, have substantially altered this state of affairs (also see Special Topic: "Canada's Oil Sands – Confounding the Doomsday Predictions?"). In Venezuela there are four projects in various stages of development. The projects currently produce about 450,000 barrels per day (b/d) of synthetic crude oil, which is expected to increase to 600,000 b/d by 2006. The FRS companies involved in these projects include Conoco and Phillips (now Conoco Phillips), Exxon Mobil, and ChevronTexaco. In Canada, Shell Canada, a unit of Royal/Dutch Shell, and ChevronTexaco are investing in projects that will contribute to a nearly tripling of production by 2010. Since each barrel of nonconventional oil production entails 5 to 7 times the carbon emissions of conventional light oil production, these projects carry with them the risk that they may prove unprofitable should carbon emissions be limited.[h]

Liquefied Natural Gas (LNG): While the world contains vast untapped resources of natural gas, a significant portion is located in remote areas. Given the anticipated large growth in natural gas demand, firms are increasingly implementing a strategy of satisfying this demand by developing remote fields and transporting the gas to market as LNG. For example, the FRS company ChevronTexaco, along with Royal/Dutch Shell, is a partner in a project in the Tangguh field in Indonesia, owned by BP. The project is scheduled to ship its first LNG by 2005 to 2006. In Australia, a consortium of companies known as the North West Shelf Venture was recently awarded a contract to supply China's soon to be constructed Guangdong LNG terminal, China's first LNG import project. Under the deal, the Venture will supply the equivalent of approximately 118 billion cubic feet of natural gas per year in the form of LNG over a 25-year period.[i] Other companies involved include Woodside Energy, BHP Billiton, and Japan

Australia LNG. Each firm currently has a one-sixth share but this will change with the expected inclusion of China National Offshore Oil (CNOOC) in the venture.

Another example of remote natural gas reserves occurs in the Artic regions of Alaska and Canada. Almost 42 trillion cubic feet of natural gas were discovered and booked as proved reserves over 20 years ago in the North Slope of Alaska and the McKenzie Delta in Canada's Northwest Territories. Because of a lack of a market for the natural gas, it has largely been unexploited. Given that the gas resides in known reservoirs, many of which, at least on the North Slope, are already producing oil, there is little geologic risk associated with the development of the gas. However, there are huge financial risks involved: the construction of a pipeline is projected to cost up to $20 billion. While the financial risks of constructing the pipeline are large, so too are the potential rewards. At the current market price, the gas would yield revenues of approximately four billion dollars per year if delivered to the lower 48 States. Companies included in the proposed project include the FRS companies BP, Exxon Mobil, and Conoco Phillips.

Special Situations: The opening up of countries that were previously closed to exploration and development by multinational firms such as the FRS companies has given rise to several unique opportunities. Among these opportunities include Russia's Sakhalin Island, off Russia's eastern coast. Over the next four years, two groups of companies, one headed by Royal/Dutch Shell and the other by Exxon Mobil, will invest $13 billion in Sakhalin projects.[j] In terms of geological risks, the investment is a prudent one given that the island's offshore shelf is believed to contain oil and gas resources that could rival those of the North Sea. By 2006, the two current major projects, Sakhalin I and II are expected to produce 420,000 boe per day of oil and gas. The oil from the projects will either be transported to the Russian mainland or exported by tanker. The gas from the project will either be transported to Japan by pipeline or exported as LNG.

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[a]BP plc, *BP Statistical Review of World Energy* (June 2002).
[b]Energy Information Administration, "The Majors' Shift to Natural Gas" (September 2001), http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html.
[c]Wood, David, "Portfolio Optimization Benefits from Integrating Analysis of Risk, Strategy, and Valuation," *Oil & Gas Journal*, Volume 100.27 (July 8, 2002), p. 26.
[d]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[e]"This Oil's Domestic, but It's Deep and Its Risky," *New York Times* (August 11, 2002), p. 1.
[f]Energy Information Administration, "The Majors' Shift to Natural Gas" (September 2001), http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html.
[g] Special compilation by the Energy Information Administration, Office of Integrated Analysis and Forecasting.
[h]Natural Resources Canada, "Canada's Emission Outlook: An Update" (April 5, 2001). Web site: http://climatechange.nrcan.gc.ca/english/Publications.asp?x=3 (as of November 10, 2002).
[i]"NWS to supply Guangdong LNG, partner with CNOOC," *Oil & Gas Journal* (August 19, 2002), p. 9.
[j] "For Big Oil, Open Door In Far East Of Russia," *New York Times* (August 6, 2002), p. W1.

SPECIAL TOPIC: Venezuela -- Half Open or Half Closed to Private E&D Investment?

In the mid–1970's, the Venezuelan government nationalized the petroleum properties of the FRS and other multinational oil companies with operations in Venezuela. Over the next decade and a half, especially after the oil price collapse of 1986, oil production in Venezuela largely languished as a result of under investment and lack of access to new technologies. However, policymakers began to rethink their policy of state ownership of oil production in 1989. At that time, the Venezuelan government began to develop a policy known as "Apertura Petróleos" (or Petroleum Opening) that encouraged foreign investment in its oil industry. The central goal of the new policy was to increase Venezuela's productive capacity, either through the rejuvenation of its mature existing fields, the discovery of new fields of medium and light crude outside of the traditional producing regions, or the development of its huge resources of extra-heavy crude oil.

There is little doubt that policy change had a major stimulative effect on Venezuela's upstream capacity. For instance, in the first phase of the program in the early 1990's, a total of 14 contracts were awarded to private companies to operate fields that were either inactive or had been abandoned. Under these contracts, the operator made a 20-year commitment that mandated certain minimum investment levels. In return, the operator received a fee for each barrel of oil produced. While the potential for these projects was originally estimated to be 125,000 barrels per day (b/d), they soon grew to more than twice this volume. In 1996, the Venezuelan Congress authorized profit sharing agreements under which private firms have the right to explore and develop new fields of light oil outside the traditional producing region. The Venezuelan Congress also approved four joint ventures between Petróleos de Venezuela, (PdVSA), Venezuela's state-owned oil company, and several multinational companies, including some of the FRS companies. There was even talk of taking the policy one step further by privatizing PdVSA.[a]

In December 1998, Hugo Chávez won Venezuela's presidential election with 56 percent of the vote, running on a populist agenda. Privatization of PdVSA was explicitly banned under the new constitution that he proposed in 1999. Moreover, a new hydrocarbons law was decreed in November 2001. Royalty rates on oil production were increased from 16.6 percent to 30 percent. Projects that can prove that they would not be financially viable at the new 30-percent rate would be allowed the lower rate of 20 percent. In addition, PdVSA must hold a 51-percent stake in any new exploration and production agreements.

In natural gas, PdVSA traditionally has had a monopoly on Venezuelan natural gas production. Further, while the country has 58 percent of the gas reserves in Central and South America, its production is only 29 percent of the region's total.[b] In contrast to the Chavez policy on oil and to the surprise of some analysts, the Chavez government enacted legislation in 1999 to stimulate gas production by opening up the sector to foreign investment in exploration, production, distribution, transmission, and gasification (although no company would be allowed to explore, produce, and transport in the same region). This law sets royalty payments at 20 percent and income-tax rates at 34 percent.

Following through on the legislation, in August of 2002 the government reached an accord with the FRS company ChevronTexaco, and also BP[c], Britain's BG Group, Statoil, and TotalFinaElf, to explore and develop four blocks in the 10,800 square mile Plataforma Deltana offshore field.[d] There is a possibility that another FRS company, Exxon Mobil, will develop a fifth block. This area is located near Venezuela's border with Trinidad and is estimated to contain 20 trillion cubic feet of natural gas.[e] Under the terms of the agreement, PdVSA will own up to a 35-percent interest in the projects. Development plans call for the gas to be exported to the United States, Europe, and Brazil in the form of liquefied natural gas.

Note: At the writing of *Performance Profiles*, the political situation in Venezuela is exceptionally fluid and subject to change, which may alter the environment for private E&D.

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[a]Katsouris, Christina, "PDVSA chief mulls sale of minority stake in firm as country reforms petroleum sector," *The Oil Daily (*April 24, 1996), p. 1.
[b]BP plc, *BP Statistical Review of World Energy,* (June 2002), pp. 20 and 22.
[c]"Venezuela Opens Offshore Field to Foreign Firms," *Wall Street Journal,* (August 26, 2002), p. A8.
[c] BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[d]Alexander's Oil and Gas Connections, "Seven oil majors sign agreement for Plataforma Deltana region," Volume 7, Number 18, (September 19, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cnl23899.htm (as of November 18, 2002).

SPECIAL TOPIC: FRS Companies in Russia and China -- A New Era?

Given Russia's bountiful hydrocarbon resources, there was considerable optimism at the time of the Soviet Union's collapse that the country would soon be a lucrative target for upstream investments by multinational oil companies, including the FRS companies. This optimism was soon dashed by the unsettled conditions of Russia's property rights and tax code structure. However, in recent years, there is evidence that Russia is reforming its policies in light of the reality that an onerous tax code is not conducive to investment. China also has increased reliance on market forces, which, along with its seemingly ever-increasing demand for energy, has led some to conclude that a new era in China's energy sector is emerging.

Russia began restructuring its oil and gas sector in 1993 by reorganizing its state-owned enterprises as joint-stock companies.[a] This resulted in the creation of a group of large, vertically-integrated companies, such as LUKoil, YUKOS, Gazprom, Surgutneftegaz, Tyumen Oil (TNK), Tatneft, and Sibneft. Since then, the government has auctioned off large quantities of its shares in these companies. For example, in 1999 the government auctioned 9 percent of Lukoil for $200 million (plus $240 million in investment commitments) and 48.7 percent of TNK for $90 million (plus $184 million in investment commitments). Despite this trend toward privatization, foreign investment in Russia's oil sector has been muted because of the business environment and tax regime. When Russia passed production-sharing agreement (PSA) legislation in the mid-1990's, the legislation was widely viewed as failing to adequately protect foreign investment, and few agreements were concluded. International oil companies claim a stable PSA regime could unlock tens of billions of dollars of investment in Russia's oil sector, but Russia's parliament has been unable to agree on a final form for a national PSA model.

Some observers argue that progress is being made in improving Russia's business climate. According to David O'Reilly, chairman and chief executive of ChevronTexaco "…considerable progress has been made in regulatory reforms, tax reform and improvement of the judiciary system" and "…most of what is left to be done will probably be complete by 2003."[b]

In the early 1990's, project-specific PSAs were put into effect. Two of these PSAs are located on Sakhalin Island, off Russia's eastern coast. For a discussion of these projects, see "Upstream Investment Focuses on Natural Gas, Large Projects." Development of ChevronTexaco's Kirinsky block in the offshore Sakhalin III project is contingent on the proposed final form PSA legislation. At this time, the proposed code is still being considered by the Russian Parliament. Development of the field would probably begin no sooner than 2005, even if the new legislation is approved in early 2003.

To help meet its projected increase in natural gas demand, China has embarked on an ambitious program to increase its domestic production of natural gas. The most notable example of a policy shift is the recent approval of an $8.5-billion project to develop gas reserves in the Tarim basin in the western part of the country and move the gas by pipeline to Shanghai and other eastern cities.[c] The 2,584-mile-long pipeline would initially deliver 424 billion cubic feet of natural gas per year to the eastern markets. In 2002, PetroChina signed a framework for a joint venture with Royal/Dutch Shell, Exxon Mobil, and Gazprom. Under the agreement, PetroChina and Sinopec (China Petroleum & Chemical) would have a combined 55-percent equity interest in the project, while the outside partners would each have a 15-percent interest. One issue clouding the development of the project is its economic viability in light of China's low energy prices and the large costs of transporting the gas over 2,600 miles. Another issue is whether the Tarim basin has sufficient gas resources to fill the pipeline over its projected 45-year life. While some have suggested that possible shortfalls in supply could be avoided if the pipeline were to go through Russian territory in order to gain access to Russian supplies, this option would significantly increase the cost of the overall project.

In a separate development, Royal/Dutch Shell recently announced that it would invest $400 million to develop two offshore blocks in China's Bohai Sea.[d] Shell and its partner, China National Offshore Oil, have identified 600 to 700 million barrels of proven oil reserves and 1 trillion cubic feet of proven natural gas reserves in the two blocks. Kerr-McGee is also active in this offshore area. The company has five Bohai Bay discoveries to date and has recently announced plans to develop one of them using a floating production, storage, and offloading vessel. It projects production from the discovery to exceed 50,000 barrels per day by mid-2005.[e]

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[a]Energy Information Administration, "Russia: Energy Sector Restructuring" (April 2002), http://www.eia.doe.gov/emeu/cabs/russrest.html#OIL.
[b]ChevronTexaco, "Board of Directors Completes First Overseas Meeting in Russia and Kazakhstan" (October 30, 2002), http://www.chevrontexaco.com/news/spotlight/kazakhstan.asp.
[c]This cost estimate of $8.5 billion does not include the cost of developing the reserves nor the estimated nine billion dollars to build the gas distribution system in Shanghai and the other eastern cities. See, Alexanders' Gas and Oil Connections, "Historic gas deal signed in Beijing," Volume 7, Number 15 (August 08, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cns23255.htm (as of November 18, 2002).
[d]Alexander's Gas and Oil Connections, "Shell to invest $ 400 million in China's Bohai Sea," Volume 7, Number 16 (August 23, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cns23413.htm (as of November 18, 2002).
[e]"Kerr-McGee sanctions development in Bohai Bay, China," Oil & Gas Journal Online (May 20, 2002). Located on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=144165&KEYWORD=%20%20Kerr%2DMcGee%20sanctions%20development%20in%20Bohai%20Bay%2C%20China (as of November 18, 2002).

SPECIAL TOPIC: Canada's Oil Sands -- Confounding the Doomsday Predictions?

Some experts argue that worldwide conventional oil production will peak within the next few years.[a] This prediction is based on a methodology advanced by M. King Hubbert that concludes that while the production of oil can increase for some period of time, it eventually reaches a maximum and then declines until the resource is totally depleted. In 1956, Hubbert used this methodology to correctly predict that U.S. oil production would peak in the early 1970's.[b]

However, others argue that, while conventional resources may be limited, the world has enormous resources of unconventional oil that are increasingly competitive with conventional crude.[c] One outstanding example is the case of Canada's oil sands. Canada's resources of oil sands or crude bitumen lie almost exclusively within three regions in the province of Alberta known as Athabasca, Cold Lake, and Peace River. The Alberta Energy and Utilities Board has estimated the ultimate volume of crude bitumen in place to be 2.5 trillion barrels.[d] About 370 billion barrels of this volume are believed to be economically recoverable at current prices and with current technology.[e] Of the economically recoverable reserves, about 15 percent can be recovered using surface mining where the bitumen deposits are dug from the earth, while the remaining 85 percent require the use of in situ production processes, in which a well is drilled and the bitumen is extracted, often using unconventional technologies.

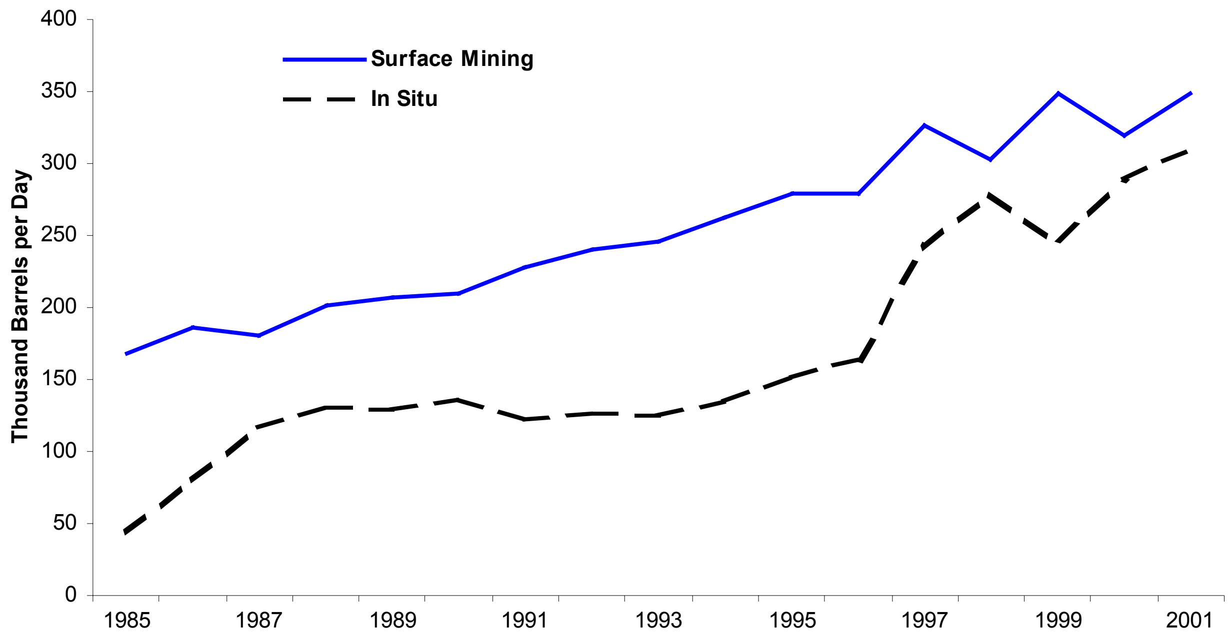
The first commercial crude-bitumen mining project in Canada commenced in 1967. While initial production was modest because of high costs, it has nevertheless steadily increased as producers have learned more about exploiting the resource (Figure 30). A reduction in the effective tax rate on oil sands production in the 1990's, along with improvements in crude bitumen mining technology, have reduced the breakeven price of surface mining operations by more than 50 percent over the past twenty years.[f] Currently, the breakeven price for mining operations is in the range of $9 to $11 (U.S. dollars) per barrel.[g]

The first commercial crude-bitumen production project using in situ techniques in Canada began in 1978. The traditional application of in situ production techniques involved drilling a well into the oil sands and extracting the bitumen almost as if it were conventional crude oil. The maturation of horizontal well technology and the development of steam assisted gravity drainage (SAGD) extraction techniques have revolutionized the in situ production industry. With the SAGD technology, two horizontal wells are drilled into the same reservoir, one directly above the other (Figure 31). Steam is injected into the top well, which heats up the surrounding tar-like bitumen and causes it to drain with the aid of gravity into the well bore of the lower well (Figure 31).

While the cost of drilling the wells with SAGD technology is considerably higher than for a conventional vertical well, the productivity levels of the wells are increased dramatically. For example, it is not atypical for a well with these advanced technologies to produce 1,000 barrels per day (b/d) of bitumen. This is more than 20 times the productivity of the average bitumen well in Alberta.[h] Because of the high productivity of the wells, these technologies are believed to have reduced the breakeven supply price to $4 to $5 (U.S. dollars) per barrel.[i]

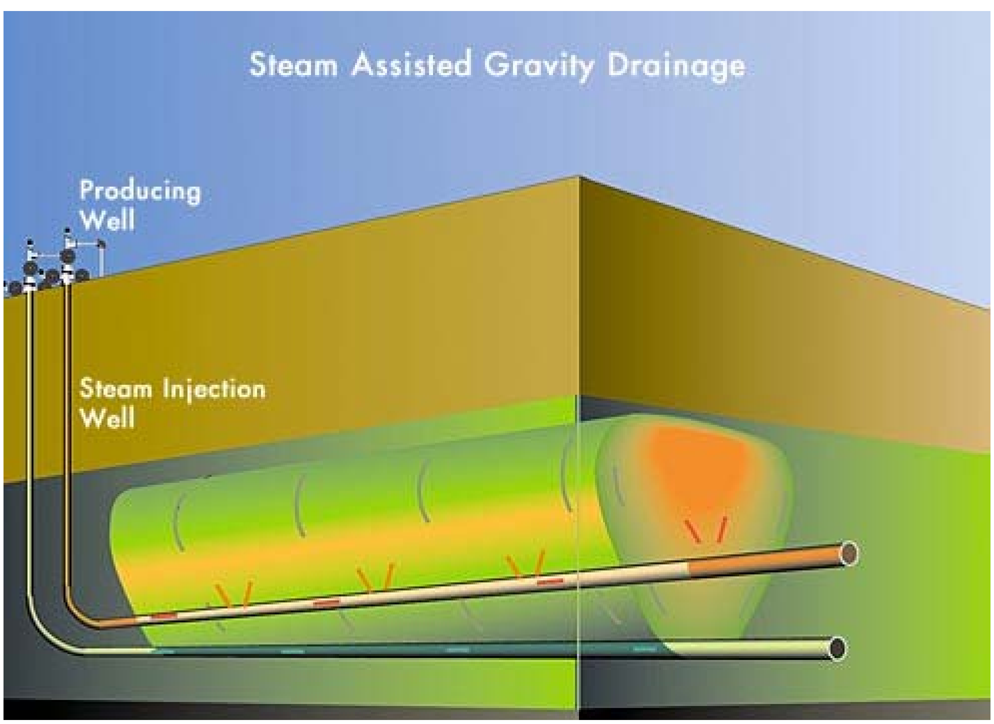
The decreases in supply costs for both mining and in situ oil sands production have encouraged oil producers to plan additional ventures. Based on publicly announced projects, production is anticipated

Figure 30. Oil Sands Production in Canada, 1985-2001



Source: Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry,* 2002, Table 2-10a and 2-10-1a.

Figure 31. Steam Assisted Gravity Drainage Technology



Source: EnCana Corporation, "Operations and Projects" section of company's web site (http://www.encana.ca/index2.shtml). EnCana Corporation is located in Calgary, Alberta, Canada. This figure is the property of EnCana Corporation and appears courtesy of EnCana Corporation.

to increase to almost 1.9 million b/d by 2010.[j] Planned, under-construction, and recently completed SAGD and oil sands mining projects (undertaken by both FRS and non-FRS companies) include:

McKay River: Petro-Canada recently started up operations at its $290 million (Canadian) SAGD MacKay River oil sands facility 35 miles northwest of Fort McMurray, Alberta. This project represents the largest commercial advanced-technology operation to date in Canada. While the project entails only approximately 30 well pairs, it is expected to produce 30,000 b/d by year-end 2003 and retain that level for the full 25-year life of the project.[k]

Firebag: This SAGD project will be operated by Suncor. The project will operate on leases covering more than 620 square miles with estimated bitumen resources of almost 10 billion barrels. The project is planned in four phases, with each phase contributing 35,000 b/d to production.[m]

Foster Creek: This project in the Cold Lake region began as a 2,000 b/d pilot project in 1997 to test SAGD technology. EnCana, a large independent producer formed by the recent merger of PanCanadian Energy and Alberta Energy, is developing the project. It is estimated that SAGD technology will enable 350 million barrels to be recovered by this undertaking.[n] Production is expected to average 20,000 b/d in 2003 and 30,000 b/d in 2004. Subsequent project phases are believed to have the potential to produce more than 100,000 b/d as early as 2007.

Cold Lake: Imperial Oil's (an affiliate of Exxon Mobil) Cold Lake operation is the largest in situ bitumen project in Canada.[o] In 2000, the latest year for which data are available, the project produced approximately 120,000 b/d of bitumen using cyclic steam-stimulation. In addition, Exxon Mobil has recently applied for regulatory approval to produce an extra 30,000 b/d of bitumen from a new operating area known as Nabiye.[p] Development of this project could be complete as early as late 2006. Exxon Mobil has also applied to expand some of its other existing operations in the Cold Lake area. It expects that these expansions will increase its total Cold Lake production to about 180,000 b/d by the end of the decade.

The Athabasca Oil Sands Project: This surface mining project has a current estimated cost of $5.2 billion, up from its original estimate of $3.8 billion. Costs are higher than expected because increased oil-sand mining and drilling has bid up the costs of constructing new facilities. The project is now on track to start up in late 2002, and will produce 155,000 b/d of bitumen at full production. Partners in the project include Shell Canada, a unit of Royal/Dutch Shell, ChevronTexaco, and Western Oil Sands.[q]

Project Millennium: Suncor Energy completed its $3.4 billion Millennium mining expansion project in late 2001. This expansion increased its production capacity to 225,000 b/d from 115,000 b/d. While costs average $16.35 per barrel in early 2002, Suncor believes that this was attributable to growing pains, and that it can drive down costs to $8.50 to $9.50 per barrel.[r]

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[a]For example, see Kenneth S. Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage* (Princeton University Press, Princeton, NJ), 2001.
[b]Hubbert, M.K, "Nuclear energy and the fossil fuels." American Petroleum Institute, Drilling and Production Practice, *Proceedings of the Spring 1956 Meetings,* San Antonio Texas, 1956, pp. 7-25.
[c]Some economists argue that the Hubbert approach is flawed because it assumes that recoverable petroleum resources are fixed, while the amount of oil which can be recovered depends on both the total amount of oil (a geological factor which is fixed), and dynamic variables like price, infrastructure, and technology**.** For more on this point, see Lynch, Michael**, "**Forecasting Oil Supply: Theory and Practice," *Quarterly Review of Economics and Finance,* v. 422, no. 2 (2001), pp. 373-389.

[d]Alberta Energy and Utilities Board, *Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011,* Statistical Series 2002-1179, http://www.eub.gov.ab.ca/bbs/products/STs/ST98-2002.pdf.
[e]Alberta Energy and Utilities Board, *Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011,* Statistical Series 2002-1179, http://www.eub.gov.ab.ca/bbs/products/STs/ST98-2002.pdf.
[f]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 35.
[g]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 35.
[h]Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry,* 2002, Tables 3-2 and 3-17a.
[i]Canadian Energy Research Institute, "Supply Costs and Economic Potential for the Steam Assisted Gravity Drainage Process" (August 1999).
[j]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 1.
[k]"Petro-Canada opens MacKay River steam-assisted oil sands facility," Oil and Gas Journal Online (October 14, 2002), http://ogj.pennnet.com/articles/web_article_display.cfm?Section=OnlineArticles&Article_Category=DriPr&ARTICLE_ID=158785&KEYWORD=Mackay%20River&x=y.
[l]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[m]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[n] Encana, "EnCana cash flow tops $ 1 billion in third quarter," Press Release (November 5, 2002).
[o] "Imperial plans $1 billion oil sands expansion," Oil and Gas Journal Online (February 20, 2002), http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=TOPST&ARTICLE_ID=92863&KEYWORD=imperial%20oil.
[p] Imperial Oil, "Cold Lake Expansion Projects," Press Release (June 4, 2002).
[q]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[r]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.

Emerging Issues

This section of *Performance Profiles* examines developments in the organizational structure of the U.S. energy industry. Specifically, this section presents three analyses ("Special Topics") that discuss:

- Consolidation in the U.S. petroleum refining industry
- A review of the major energy companies' involvement in diversified enterprises
- The FRS companies role in the U.S. liquefied natural gas markets

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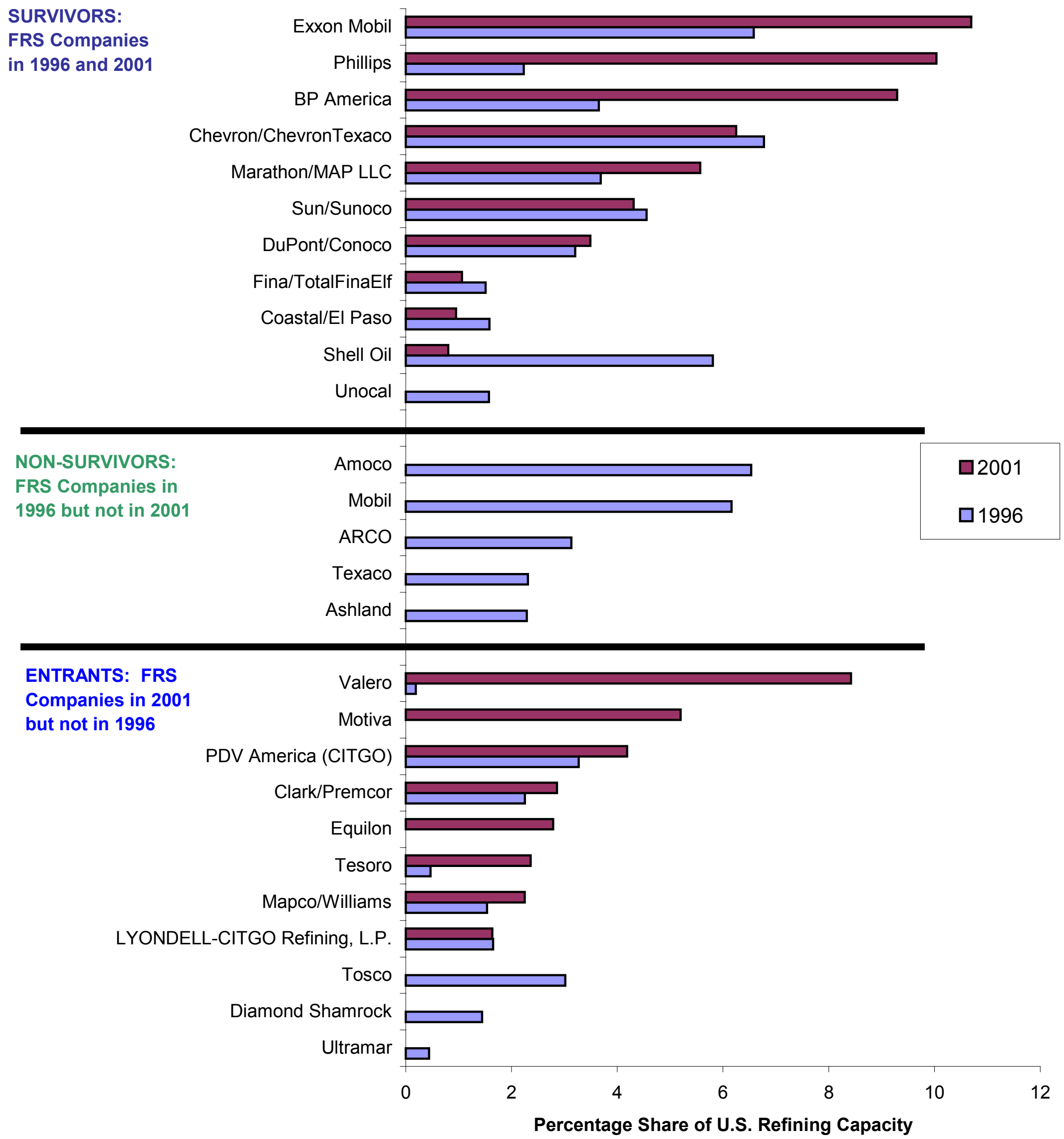
SPECIAL TOPIC: **Downstream Evolution -- Consolidation in U.S. Refining**

Recent interest in the U.S. refining industry prompted by petroleum product price spikes and subsequent Federal investigations[a] suggest an interest in the ownership structure of the U.S. refining industry. The following presentation is provided to illustrate how the industry has evolved to its current state or configuration.[b]

In order to make the review and exposition of the recent changes in the U.S. refining industry more tractable, the FRS refiners in 1996 and 2001 have been separated into one of three categories: Survivors, Non-Survivors, and Entrants (Figure 32). The Survivors are FRS companies that had U.S. refining operations or capacity in 1996 and are still FRS companies for 2001 (but don't necessarily still have refining operations or capacity). Non-Survivors were FRS refiners in 1996, but were not FRS companies in 2001. Finally, Entrants were refiners in 1996 (but not FRS companies) and had become FRS companies by 2001.

Figure 32. U.S. Refining Capacity Shares, FRS Companies, 1996 and 2001



Notes: Refining capacity is measured by crude oil distillation capacity. Also, companies that had different names in 1996 and 2001 (due to merger or other reasons) are listed with their 1996 name first and the 2001 name next with a slash separating the two names. BP America is the FRS company, and not the parent.

Source: Energy Information Administration, *Petroleum Supply Annual 1997*, DOE/EIA-0340(96)/1 (Washington, DC, June 1998), Table 40 and *Petroleum Supply Annual 2001*, DOE/EIA-0340(2001)/1 (Washington, DC, June 2002), Table 40. Web address: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html .

Examination of Figure 32 reveals the following:

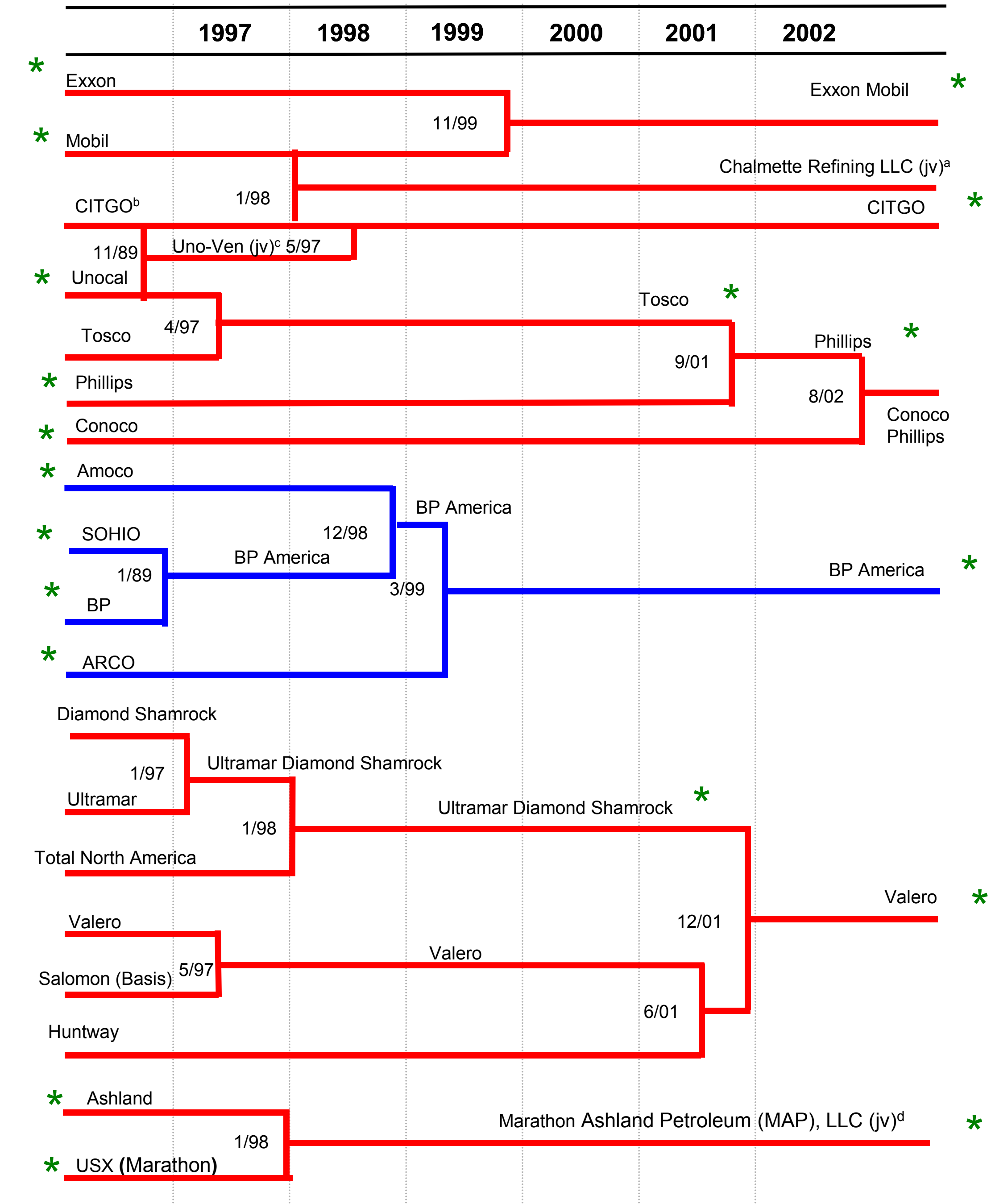
- Most (all except Unocal) of the Survivors still engage in U.S. refining and more Survivors have increased their share of U.S. refining capacity[c] than have decreased their share. On balance, the Survivors' share increased from 41 percent to 53 percent.
- All of the Survivors whose share of U.S. refining capacity grew between year-end 1996 and year-end 2001 did so almost entirely because of merger and/or direct or indirect acquisition.[d] None of the Survivors whose share of U.S. refining capacity declined were involved in mergers or acquisitions of refining assets.
- All of the Non-Survivors both exited the U.S. refining/marketing industry and the FRS survey respondent group. All of the Non-Survivors were acquired by another company (Amoco, Mobil, ARCO, and Texaco) or transferred their refining assets into a joint venture controlled by another company (Ashland).
- Some of the Non-Survivors were extremely significant refiners (i.e., Amoco, Mobil, and Texaco[e]) while others were essentially mid-level refiners (ARCO and Ashland).
- Most of the Entrants were small refiners in 1996 (CITGO and Tosco are somewhat exceptional in this regard) and became, at least in comparison, much larger (LYONDELL-CITGO Refining, L.P. is an exception) between year-end 1996 and year-end 2001.[f]
- The Entrants still in existence at year-end 2001 were almost equally divided between joint ventures (Motiva, Equilon, and LYONDELL-CITGO) and stand-alone companies (Valero, CITGO, Premcor, Tesoro, and Williams).

Not only has the U.S. refining industry undergone considerable change in the past 5 years (Figure 33), but the cast of companies composing the largest 5 or 10 refiners in the United States also has undergone substantial change (Figure 32). Perhaps the most interesting group of companies is the Entrants. These companies are non-vertically integrated refiners[g] and they collectively and individually experienced significant growth during the 1990's.[h] The companies generally pursued one of two (or a combination of the two) strategies: a) acquisition of assets, or b) acquisition of or merger with entire companies.

Generally, Tosco pursued the former strategy with the exception of its acquisition of the convenience store company Circle K in 1996. Ultramar Diamond Shamrock pursued the latter strategy, first merging Ultramar and Diamond Shamrock in 1997 and then acquiring Total North America in 1998. Probably the most prominent of all the non-vertically integrated refiners during the 1990's were Tosco and Ultramar Diamond Shamrock (UDS), both of which were prominent in the events of 2001 because each was acquired by another company. Tosco was acquired by Phillips (whose subsequent merger with Conoco was approved in August 2002) and UDS was acquired by Valero, another of the fast-growing non-vertically integrated refiners of the 1990's.[i]

Valero, too, exhibited a combination of the two strategies. Beginning with a single refinery with a total capacity of 29,900 barrels per day as recently as year-end 1996, Valero first acquired Basis Petroleum from Salomon Brothers in May 1997.[j] This single transaction increased Valero's refining capacity by more than 9-fold (to 309,500 barrels per day). Subsequently, Valero acquired Exxon Mobil's Benicia, California refinery[k] and associated retail outlets during 2000. During 2001, Valero acquired Huntway Refining (a California-based asphalt and road oil refiner) in June, El Paso's (formerly Coastal's) Corpus Christi refinery in July, and Ultramar Diamond Shamrock (UDS) in December.[l] The acquisition of UDS essentially doubled Valero's refinery capacity, adding almost 600,000 barrels of U.S. refining capacity[m] in addition to a Canadian refinery and associated marketing operations.

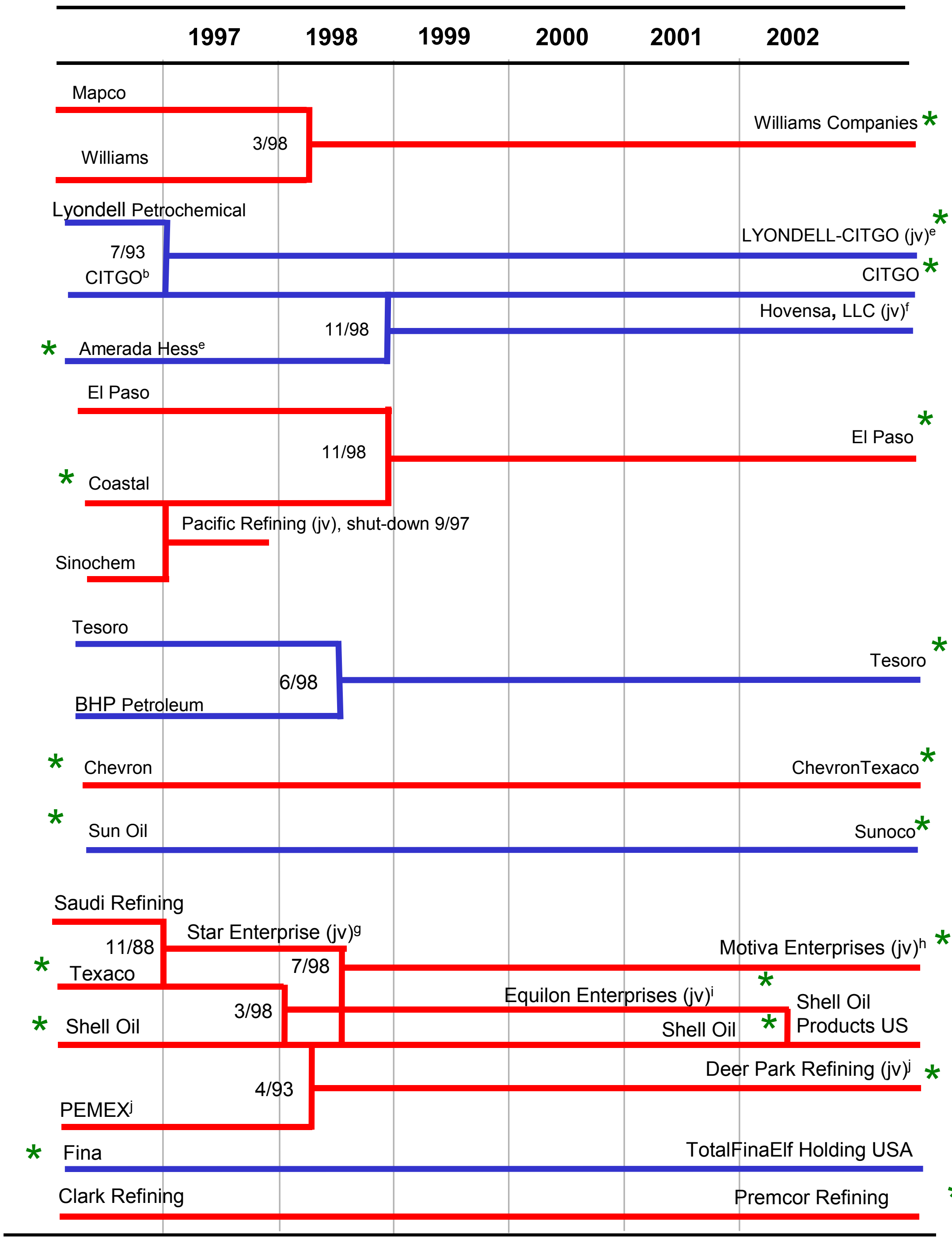
Figure 33. Genealogy of the 2001 FRS Refiners



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1997. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2001.

Footnotes and source notes are at the end of the figure.

Figure 33. Genealogy of the 2001 FRS Refiners (continued)



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1997. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2001.

Footnotes and source notes are at the end of the figure.

Figure 33. Genealogy of the 2001 FRS Refiners (continued)

[a]For the purpose of simplification, the partner of the Chalmette joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent PdVSA. Chalmette is a 50/50 joint venture.

[b]For the purpose of simplification, the partner of U.S.-based joint venture between PdVSA is given as CITGO, regardless as to which U.S. affiliate of PdVSA actually is the partner because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA).

[c]For the purpose of simplification, the partner of the Uno-Ven joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). Uno-Ven was a 50/50 joint venture, which was dissolved in May 1997.

[d]Marathon Ashland Petroleum is 62 percent owned by Marathon Oil, which formerly was known as USX Corporation. Ashland owns the remaining 38 percent of the venture.

[e]For the purpose of simplification, the partner of the LYONDELL-CITGO refining joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). LYONDELL-CITGO refining is a 50/50 joint venture.

[f]For the purpose of simplification, the partner of the Hovensa joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). Hovensa is a 50/50 joint venture that includes Hess' U.S. Virgin Islands 495,000 barrels per day refinery. It is included here because of the relative size of the refinery and its proximity to U.S. markets.

[g]Star Enterprise was a 50/50 joint venture between the U.S. affiliate of Saudi Aramco, the state oil company of Saudi Arabia and Texaco. The venture sold motor gasoline and petroleum products under the Texaco brand name in the southeastern and Midwestern U.S.

[h]Motiva Enterprises was a joint venture between Star Enterprise and Shell Oil that sold motor gasoline and petroleum products under the Shell and Texaco brand names. Motiva is now a 50/50 joint venture between Saudi Refining and Shell Oil after Texaco sold its ownership to its partners as a precondition of the U.S. Federal Trade Commission approving the merger of Chevron and Texaco.

[i]Equilon Enterprises was a 56/44 joint venture between Shell Oil and Texaco, respectively, that operated in the western United States. As a precondition of the U.S. Federal Trade Commission's approval of the merger of Chevron and Texaco, Texaco sold its ownership in Equilon to Shell Oil, which then fully owned Equilon and consolidated Equilon and its other fully owned U.S. assets into Shell Oil Products US as of March 2002.

[j]Deer Park Refining is a 50/50 joint venture between Shell Oil and Petroleos de Mexicanos (PEMEX), the state oil company of Mexico. Although this presentation may suggest that PEMEX no longer exists, this is not true. However, PEMEX has no other existence in the U.S. refining/marketing industry outside this joint venture.

Sources: Energy Information Administration, *Petroleum Supply Annual* [1997-2001], Volume 1, DOE/EIA-0340 (Washington, DC, June), Tables 40, 48, and 49; and company news releases and other public disclosures.

Further, joint ventures are a common method of attempting to reduce operating costs. A joint venture has some of the benefits of acquisition while avoiding some of the costs. Perhaps the most enticing aspect of a joint venture is that it permits what amounts to a "partial merger," allowing companies to selectively merge some operations (e.g., U.S. refining) while withholding others (e.g., all non-U.S. refining operations). PDV America and its CITGO affiliate have widely used this technique in creating refining joint ventures. Texaco, too, was involved in 3 separate U.S. refining joint ventures, beginning in 1988, and concluding with its merger with Chevron in 2001.

When one closely examines Figures 32 and 33, perhaps the most compelling conclusion is also one of the most obvious: the largest refiners in the United States are much different at the end of 2001 than at the end of 1996 (Figure 32 and Figure 33). A related point is that the path to the top has generally entailed an acquisitive journey, but the means of acquisition have varied. The most successful companies seem to have employed multiple methods of acquisition, including one or more of the following: a) company acquisition, b) asset acquisition, and c) joint ventures.

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[a] Investigations include many congressional hearings and studies, including the recent report by the Senate Permanent Subcommittee on Investigations (see, http://frwebgate.access.gpo.gov/cgi-

bin/getdoc.cgi?dbname=107_senate_hearings&docid=f:80298.pdf for the Subcommittee's report on motor gasoline prices, as of November 18, 2002), and at least one on-going investigation by the U.S. General Accounting Office.

[b] One will note that the idea for Figure 33 was provided by recent work by the U.S. Department of Energy's Office of Strategic Petroleum Reserves.

[c] Shell Oil's share of U.S. refining capacity decreased between year-end 1996 and year-end 2001 because almost all of its U.S. refining capacity was placed in the joint ventures Equilon and Motiva. However, since March 2002 the capacity of Equilon has been consolidated within Shell Oil, which was then renamed Shell Oil Products US, following Texaco's divestiture of its shares of Equilon and Motiva as of February 13, 2002. See, Shell Oil Company, press release (February 13, 2002). Web site: https://www.piersystem.com/external/final_View.cfm?pressID=8398&CID=69 (as of November 13, 2002).

[d] Marathon's Marathon Ashland Petroleum LLC joint venture is an example of indirect acquisition as Marathon effectively acquired control over Ashland's refining/marketing assets through the creation of the joint venture, which is controlled by Marathon because of its 62-percent ownership of the joint venture.

[e] Texaco's refinery capacity in 1996 was diminished considerably through its participation in the Star Enterprise joint venture with Saudi Refining (the U.S. affiliate of the state oil company of Saudi Arabia, Saudi Aramco) in which more than half its refining capacity was committed beginning in November 1988.

[f] Diamond Shamrock, Tosco, and Ultramar may seem to also be exceptions, but were acquired during 2001. Tosco was the 3rd-largest refiner in the United States at the end of 2000 and Ultramar Diamond Shamrock was the 10th-largest. See, Energy Information Administration, *Petroleum Supply Annual 2000*, Volume 1, DOE/EIA-0340(2000)/1 (Washington, DC, June 2001), Tables 36 and 40. Web site: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html (as of November 12, 2002).

[g] Williams Companies, which is perhaps best described as an energy services company, is an exception to this generalization. However, its inclusion in the FRS is based on its March 1998 acquisition of Mapco, an non-vertically integrated refiner.

[h] See Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), pp. 60-64. Web site: http://tonto.eia.doe.gov/FTPROOT/financial/020697.pdf (as of November 12, 2002).

[i] Phillips, too, had a smaller transaction in 2000 in which it acquired some of ARCO's Alaskan assets as part of the consent agreement that resulted in the U.S. Federal Trade Commission's approval of the BP Amoco (now BP) acquisition of ARCO. In addition to crude oil producing properties, Phillips acquired ARCO's Alaskan refineries, one of which was subsequently sold to BP during 2001.

[j] Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0384(97) (Washington, DC, June 1998), Table 38. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/1997/psa_volume1_1997.html (as of November 12, 2002).

[k] Energy Information Administration, *Petroleum Supply Annual 2000*, Volume 1, DOE/EIA-0384(2000) (Washington, DC, June 2001), Table 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2000/psa_volume1_2000.html (as of November 12, 2002).

[l] Energy Information Administration, *Petroleum Supply Annual 2001*, Volume 1, DOE/EIA-0384(2001) (Washington, DC, June 2002), Table 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2001/psa_volume1_2001.html (as of November 12, 2002).

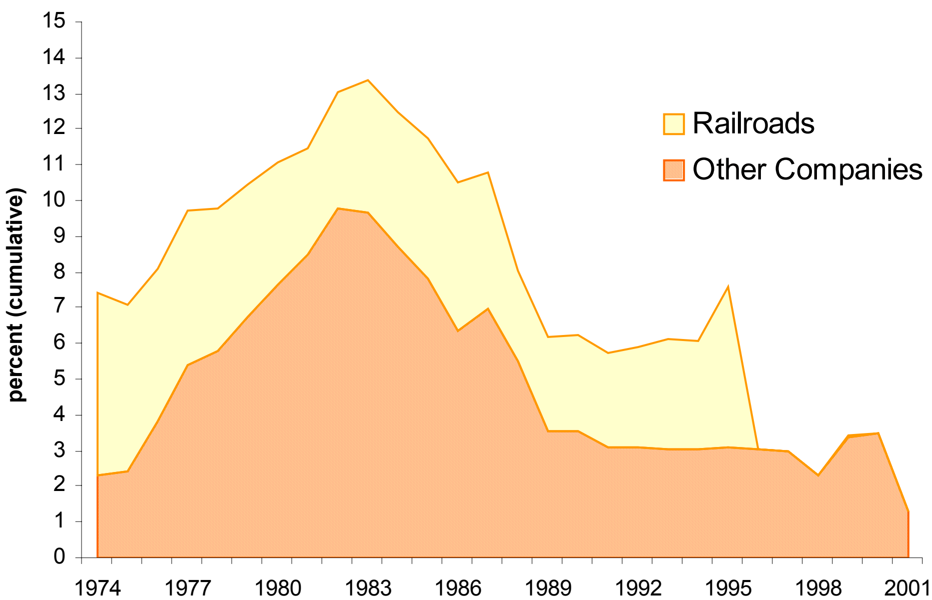
[m] Energy Information Administration, *Petroleum Supply Annual 2001*, Volume 1, DOE/EIA-0384(2001) (Washington, DC, June 2002), Tables 40 and 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2001/psa_volume1_2001.html (as of November 12, 2002).

SPECIAL TOPIC: Telecommunications -- The End of the Line for Diversification?

Businesses beyond energy and chemicals have had a varied history as targets of investment of FRS companies. This special topic provides a brief review of the major energy companies' involvement in diversified enterprises and factors that influenced it over the 1974 through 2001 span of FRS data collection.

These diversified enterprises are classified in the "other nonenergy" line of business for FRS purposes. The FRS companies' commitment to other nonenergy, as measured in this line of business' share of total net investment in place (i.e., net property, plant, and equipment plus investments and advances), reached a peak of 13 percent in 1983 (Figure 34). Almost 20 years later, the comparable share was only 1 percent in 2001. At its height of interest, capital expenditures for other nonenergy ranked only behind U.S. oil and gas production and foreign oil and gas production among the FRS lines of business.

Figure 34. Other Nonenergy Share of Net Investment for FRS Companies, 1974-2001



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

It should be noted first that investment in railroad operations was, until 1996, a significant component of the investment base in the other nonenergy line of business. Burlington Northern and Union Pacific were originally selected as FRS respondents because of their prominence in U.S. coal production and large holdings of U.S. coal reserves. By the mid-1980's, Burlington Northern had become a major U.S. natural gas producer. In 1987, Burlington Northern separated its railroad operations from its energy operations by spinning off Burlington Resources to its shareholders. Burlington Resources has been the FRS respondent since then. Union Pacific was a vertically integrated petroleum company as well as a leading railroad company when selected for the original FRS respondent group. In the late 1980's, Union Pacific divested its refining and marketing operations. In 1996, Union Pacific separated its railroad and other transportation operations from its energy operations when it spun off Union Pacific Resources Group to shareholders. Another FRS company, Anadarko Petroleum, subsequently acquired Union Pacific Resources in 2000.

The focus of this review is on the diversification patterns of FRS companies other than the railroads. Inspection of Figure 34 suggests that the FRS companies' involvement with diversified businesses can be divided into five periods.[a]

1974 to 1983 – Investment in Diversified Businesses Grows Rapidly

The 1974 to 1983 period was the period of greatest growth for the other nonenergy line of business. The asset base in other nonenergy grew more than five-fold, thirteen-fold excluding the railroads. All but five of the then 26 FRS companies participated in this upswing in capital expenditures. Newcomers to diversification made the bulk of these investments. The 15 companies with less than 5 percent of their investment base allocated to other nonenergy in 1974 accounted for nearly 90 percent of the growth in capital expenditures for diversification efforts.

Some of the targets of diversification reflected transference of expertise from core petroleum and chemical operations to nonenergy industries. (Integrated petroleum and chemical manufacturing in the FRS context include the functions of extraction, bulk movement and storage of commodities, marine transport, refining, distribution, and marketing to final consumers, including advertising, credit, and direct mail.) Related diversification moves during this period included investments in primary metals and nonfuel minerals mining, engineering and construction, real estate development, timber, agribusiness, trucking, insurance, computer services, and direct mail retailing. More conglomerate moves included department stores, automobile parts, shipbuilding, meatpacking, cable television, and office and other electronic equipment.

The FRS companies' commitment reached a peak in 1983, a year after DuPont and USX became FRS companies through their acquisitions of Conoco and Marathon, respectively.

Why were the U.S. major energy companies pursuing nonenergy prospects at the time that oil prices were escalating, reaching over $60 per barrel (in 2001 dollars)?

During this period, many of the majors were constrained in their opportunities to invest in oil and gas production. Nationalizations of oil reserves by key oil-producing countries eliminated a substantial amount of upstream prospects abroad. Other oil-producing countries adopted policies that discouraged foreign investment in oil and gas. The majors turned increasingly to U.S. oil and gas development as the target of their upstream investment. Hordes of other companies were entering U.S. oil and gas development as well, in part encouraged by high oil prices, in part encouraged by tax laws then that specifically favored producers other than the majors. The result was an unprecedented level of drilling that served to drive up the costs of finding oil and gas, reducing the attractiveness of U.S. oil and gas investment for the majors.

Downstream operations in the United States and abroad were experiencing a diminished outlook for petroleum demand. Sharply higher petroleum product prices induced conservation and other efforts to reduce petroleum consumption. In the United States, policies at the time encouraged the building of refinery capacity by companies other than the majors, resulting in an excess of basic refining capacity. Thus, developments in oil and gas markets during the 1974 to 1981 period of oil price escalations had some tendencies to push the majors to investment targets outside of oil and natural gas.

Also driving the majors to invest generally was the simultaneous surge in cash flow at the time that crude oil prices were escalating: between 1974 and 1981, cash flow from operations more than tripled. Corporate culture and tax laws at the time strongly favored reinvestment of cash flow rather than payouts to shareholders such as dividends.

1984 to 1989 – Consolidation and Retrenchment

Falling oil prices, developments in the capital markets, and poor returns to nonenergy investments reversed the trend toward nonenergy diversification.

Oil prices began to decline in late 1981, falling from $37 per barrel to $27 per barrel in 1985. Oil prices then crashed in 1986, falling to $11 per barrel in July.[b] The resulting drop in cash flow tended to reduce investment generally, and diversification in particular.

Capital markets were changing. Shareholders were demanding rates of return at least as good as those available in global capital markets. The view of investors was that reinvestment should only be undertaken if it could match or better these returns; otherwise cash flow should be paid out to shareholders. Major energy companies had to cope with declining cash flow, lower expected returns from oil and gas production, and shareholder demands for greater payouts. Investments in businesses outside of core competencies became harder to justify.

Diversified businesses became targets of retrenchment for the FRS companies. The profitability of these operations had been low and declining. Divesting those businesses with subnormal performance would raise overall rates of return as well as providing cash.

Excluding the railroads, the FRS companies' asset base in other nonenergy declined by 62 percent between 1983 and 1989. Companies making multi-billion dollar divestitures of nonenergy businesses included Standard Oil of Ohio (now BP[c]), ARCO, and Mobil. Texaco sold most of the nonenergy assets gained in its acquisition of highly diversified Getty Oil in 1984. The most diversified company, Tenneco, left energy altogether in 1988, thereby reducing the FRS companies' apparent commitment to diversified enterprises.

Retrenchment paid off, as the rate of return to the other nonenergy line of business generally rose over the period.

1990 to 1997 – Reduced Commitment Appears to Hold Steady

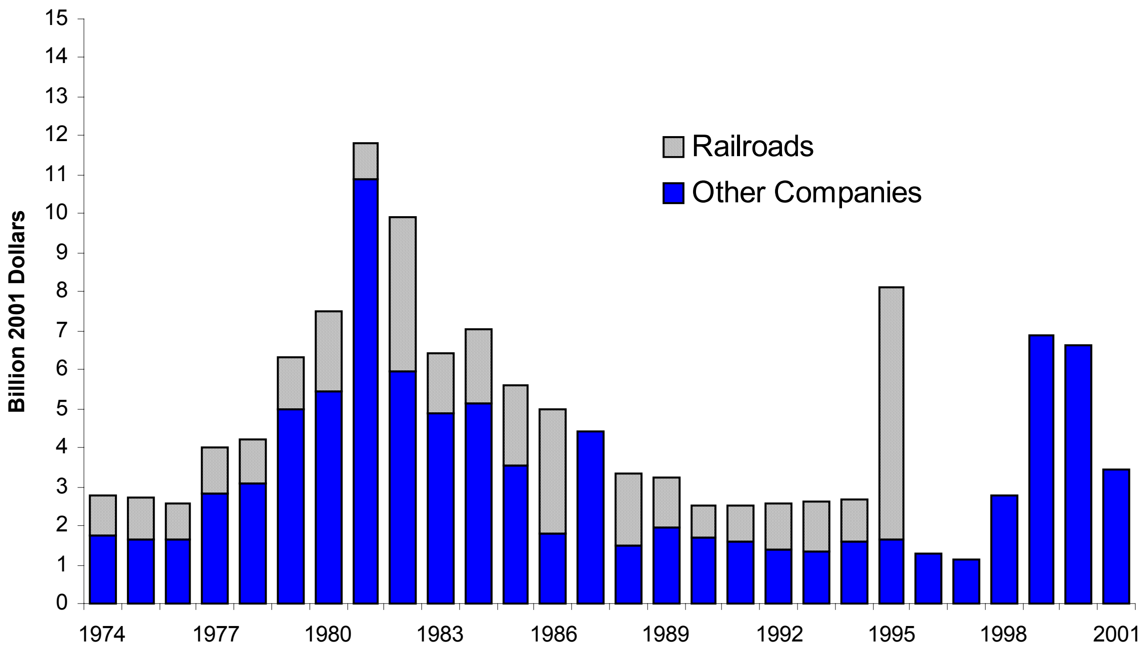
Excluding the railroads, the FRS companies' net investment in place in other nonenergy changed little, both in value and as a share of total net investment. However, most companies reduced their commitment to this line of business during the 1990 to 1997 period. BP, Kerr-McGee, Occidental Petroleum, Sunoco, and Texaco completed their exits from the other nonenergy line of business.

An exception to this trend was Exxon Mobil. Over the period, this company continued to add to their asset base in Chilean copper production and electricity production in Hong Kong. Hong Kong Electric was classified in the other nonenergy line of business until 1998. Exxon Mobil reclassified the subsidiary into the "other energy" line of business per EIA request. This change largely accounts for the dip in the other nonenergy share of net investment in 1998.

1998 to 2000 – The Short-lived Telecommunications Boom

In 1997, capital expenditures for the other nonenergy line of business, adjusted for inflation, were at the lowest level over the 1974 to 2001 period of FRS data collection (Figure 35). Capital expenditures then surged in the 1998 to 2000 period, reaching a level second only to that of 1981. The upswing was largely due to investments in telecommunications. (Telecommunications in this context consists mostly of fiber optic networks but also includes broadband services.) The investments appear to have been premised on achieving synergies with existing pipeline networks and energy trading operations.

Figure 35. Other Nonenergy Additions to Investment in Place, 1974-2001



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Taking advantage of their transmission and distribution networks, Williams Companies and Enron led the investment in telecommunications. Williams owned or leased and operated a national inter-city fiber optic network. These assets were used to provide communications services to a variety of businesses. Williams reported capital expenditures for its "Communications" business of $0.5 billion in 1997 and 1998, $1.7 billion in 1999, and $3.4 billion in 2000.[d] Enron, through 2000, was constructing a fiber optic communications network in the United States and had related facilities in Tokyo and seven major European cities. Enron reported ownership and contractual interest of 18,000 miles of fiber optic network capacity in the United States. The company also reported that it was developing a trading platform for broadband services.[e]

Enron also made other sizable investments in other nonenergy businesses during the period. In 1998, Enron acquired water supply and wastewater services assets in the United Kingdom for $0.9 billion. These assets were the core for Azurix, a global water and wastewater services business. In 2000, Enron acquired MG plc, an international metals trading company, in a transaction valued at $2.0 billion.

2001 – Telecommunications Divested, U.S. Steel Departs

In April 2001, Williams Companies spun off its subsidiary, Williams Communications, to its shareholders. This transaction excised the company's telecommunications business from the FRS database. Enron, and its nonenergy assets, exited the FRS due to its bankruptcy filing in December 2001 (see the Highlight entitled, "What Factors Undermined Enron's Success in Energy Trading?" in Chapter 3). In April 2001, FRS company USX announced its intention to spin off its U.S. Steel subsidiary to shareholders. The spin off (separating U.S. Steel's operations from the FRS database and leaving Marathon Oil as the FRS respondent) was completed at year-end.

The above developments accounted for the fall in capital expenditures for other nonenergy in 2001. In 2001, the other nonenergy line of business' share of total net investment of the FRS companies was down to 1 percent (Figure 34).

Are there any prospects for a resurgence of nonenergy businesses as targets of investment of the U.S. major energy companies? Based on past experience and the realities of today's capital markets, it seems unlikely that even another huge increase in cash flow comparable to that of the 1974 to 1981 period would induce an upswing in diversification. One possibility, though, lies in development and manufacture of plant and equipment for renewable energy production. Examples include solar energy systems and wind energy turbines.[f] Investments such as these, although directed ultimately to energy production, would be considered to be in manufacturing and fall into the other nonenergy line of business.

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[a]The first two sections draw on material first presented in Chapter 6 of *Performance Profiles of Major Energy Producers 1993* http://www.eia.doe.gov/emeu/finance/histlib.html
[b]Energy Information Administration, *Historical Monthly Energy Review* 1973-1992, DOE/EIA-0035(73-92)(Washington D.C., August 1994), p. 249.
[c]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[d]The Williams Companies, Inc., 2000 Securities and Exchange Commission Form 10K, p. F-62.
[e]Enron Corporation, 2000 Securities and Exchange Commission Form 10K, p. 11.
[f]For example, see BP at http://wwww.bp.com/environ_social/environment/renew_energy/our_perform.asp and Shell Oil at http://www.shell.com/home/Framework?siteId=rw-br.

SPECIAL TOPIC: The FRS Companies Refocus on LNG

Liquefied natural gas (LNG) is natural gas that has been chilled sufficiently to become liquid in form. For analytic purposes, LNG is best viewed not as a separate fuel unto itself, but instead simply as natural gas that has been transformed into liquid form. Natural gas is converted to liquid form primarily for transportability by water, since there may be insufficient or no natural gas pipeline capacity in the production area to transport the natural gas anywhere, or at least to the desired marketing area. Landlocked areas with natural gas resources require a pipeline for delivery to a body of water for shipping. Once converted to LNG, the gas is transported in chilled containers aboard ship.

The first appearance of LNG to any significant commercial extent was in the 1960's in Algeria.[a] In the 1970's the first LNG projects in the United States were initiated, due to the economic environment --

domestic natural gas prices had increased to high levels, and government regulation of the natural gas market had contributed to creating supply shortages.

In the 1980's, the tight market situation eased as natural gas prices dropped dramatically, contrary to the long-term expectations formed during the 1970's. As domestic supplies of natural gas proved sufficient, the LNG market in the United States shrunk, the result being that operations at two of the four LNG import facilities in the U.S. were discontinued.

In the 1990's, a variety of developments occurred leading to the reemergence of a stronger LNG market, on both the supply and demand side. Consumption of natural gas has increased steadily, as it has become a fuel of choice for environmental reasons. In the electric power generation sector, advances in natural gas-fired generation technologies such as combined-cycle technologies have boosted demand significantly, as most electric generation capacity additions are natural gas-fired.

In addition, the growth of oil production has, as a byproduct, led to increased availability of natural gas suitable for little else but to be transformed into LNG. Oil exploration and development has gradually moved to more remote areas, including many offshore sites, where there is no pipeline infrastructure to market the associated natural gas that is produced. As a result, more "stranded gas" needs to be dealt with, some of which is currently just flared. This gas represents a low-cost source of supply of natural gas suitable for LNG.

Meanwhile, costs of delivering natural gas in liquefied form have declined throughout the supply chain in recent years.[b] Liquefaction costs have declined. Shipping costs have also declined as ships employ more modern technologies. In addition, companies continue testing new technologies, such as regasifying the LNG on specialized ships located offshore the market area, which may have the potential to further boost LNG trade volumes.

In the post-2000 era, natural gas prices are expected to rise to $3.26 per thousand cubic feet (mcf) (in 2001 dollars) in the year 2020.[c] Demand is expected to continue to grow, and domestic supplies are expected to be insufficient by themselves to meet that demand. Imports of natural gas by pipeline from Canada are expected to remain the main supplement to domestic supplies. However, LNG represents an additional source of supply for domestic needs and is expected to grow significantly.

The United States imported 238 billion cubic feet (bcf) of LNG in 2001, with 93.9 percent of the total coming from Trinidad, Algeria, Nigeria, and Qatar (Table 23). The United States exported 7 billion cubic feet of LNG in 2001 to two countries, Japan and Mexico; all but 0.6 percent goes to Japan, and is exported from the Kenai LNG Marine Terminal on Alaska's Kenai Peninsula.

Table 23. LNG Imports to the United States by Origin, 2001
(Million Cubic Feet)

	Algeria	Australia	Nigeria	Qatar	Trinidad	Other	Total
Imports	64,945	2,394	37,966	22,758	98,009	12,055	238,127

Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2002/09) (Washington, D.C., September 2002), Table 5.

The FRS companies play an integral role in the domestic LNG market. The FRS companies own two of the four LNG import and regasification facilities on the mainland United States, as well as the sole U.S. liquefaction and export facility, which is on Alaska's Kenai Peninsula.

As discussed in the EIA report *The Majors Shift to Natural Gas* (link to http://www.eia.doe.gov/emeu/finance/sptopics/majors/ind), the FRS companies have increasingly become natural gas companies. Since these companies have significant experience with all aspects of natural gas markets and technologies, they are well positioned to be leaders in the development of LNG projects and growth of LNG markets. In addition, due to their size they tend to have the "deep pockets" helpful to finance such large-scale projects, including liquefaction facilities, LNG ships, and regasification facilities.

Existing and Planned LNG Facilities of the FRS Companies

To see how the FRS companies plan on using their capital to ensure their place in the domestic as well as worldwide LNG market, it is useful to understand what their current LNG plants and projects are, and what planned facilities they have announced, both domestically and abroad.

El Paso Corporation. El Paso has only one existing LNG facility, an LNG terminal at Elba Island, near Savannah, Georgia. This facility, which has a capacity of 446 million cubic feet (mmcf) per day, is owned by El Paso's subsidiary Southern LNG.[d] Although the facility was mothballed in 1982, it was reactivated in December 2001. Activity at this reopened facility has been slow; over six months passed before a second LNG cargo arrived in April, from Trinidad.

Nonetheless, El Paso plans a major expansion at Elba Island. By 2005, the company plans to expand the terminal's storage capacity by 3.3 bcf, or approximately 80 percent, to 7.3 bcf.[e] This expansion will increase the facility's regasification send-out rate by 360 mmcf per day, to approximately 800 mmcf per day. The company estimates the expansion will cost $145 million. The facility will supply natural gas to markets in Georgia, Florida and South Carolina.

The existing 446 mmcf per day LNG capacity is owned by another El Paso subsidiary, El Paso Merchant Energy Company, which holds the right to 100 percent of that capacity. Relative to the planned expansion, however, Shell Gas & Power has contracted with El Paso for rights to all of that additional capacity, for a 30-year term. This capacity will provide an outlet for West African and South American LNG projects in which Shell has ownership interests.

In addition, El Paso has explored a variety of other potential LNG projects, mainly new regasification terminals. Some or all of the facilities would be offshore, using regasification ships that El Paso would commission specifically for the purpose of receiving supplies from traditional LNG ships. Offload rates would be 400-500 mmcf per day, a rate slower than with conventional regasification terminals due to the lack of floating storage facilities. The following list enumerates the leading options, although it is not clear at this time which of these projects will actually come to pass.

Regasification Facilities

- Baja California, Mexico: El Paso Global LNG and Phillips Petroleum Company are jointly developing plans for an LNG regasification terminal in Baja California, Mexico to provide supplies to California and northern Mexico. The facility would deliver approximately 212 bcf per year of LNG to markets in Southern California and Mexico's Baja California peninsula.[f] Supplies of LNG would be purchased by El Paso from a plant to be built by Phillips near Darwin, Australia. Once transported to and regasified at the new LNG terminal in Baja California, this will provide a new source of natural gas supplies to the growing Southern California markets. El Paso would be the marketer of the natural gas. Plans are for LNG sales to El Paso to begin in 2005.

- Altamira, Mexico: El Paso Global LNG and Shell Gas and Power have signed an agreement for construction of a 0.5-to-1.0-bcf-per-day LNG regasification terminal in Mexico's east coast Tamaulipas state at Altamira.[g] The joint venture facility would receive gas from Africa, the Caribbean, and South America and provide supplies to northeastern Mexico, primarily for increasing electric power usage.

- The Bahamas: El Paso Global LNG has developed plans for an LNG terminal in the Bahamas. If built, this terminal could be linked with the Bahama Cay international pipeline and the associated Bahama Cay pipeline. In October 2001, each of these pipelines held open seasons to measure shipper interest in capacity on the combined 125-mile system.[h]

Shipping Services

In tandem with El Paso's plans for LNG receiving and regasification facilities, El Paso is contracting for transportation services for the proposed offshore gas terminals. The El Paso subsidiary El Paso Shipping Holding Company has entered into four long-term charter party arrangements for LNG vessels and holds options for charter parties on additional vessels. The ships would be constructed in South Korea with deliveries commencing in 2003.[i]

Natural Gas Supplies

Completing the planning picture, El Paso Global LNG has entered into several contracts for LNG supply.[j] One is a contract entered into in October 2001 with the Snohvit Sellers Group of Norway to bring 88 bcf of LNG to the North American east coast. Another is a contract with Port Fortin LNG Export Partners providing access to 102 bcf of LNG from Port Fortin, Trinidad.

The Williams Companies. As of the end of 2001, Williams' biggest LNG facility is its major import and regasification facility at Cove Point in Lusby, Maryland. It connects to the Williams Gas Pipeline's Transco system, delivering supplies to the Mid-Atlantic region. The facility has a storage capacity of 5 bcf, and a regasification send-out capacity of 1 bcf per day, with capacity to expand to 3 bcf per day.[k] Cove Point will become the nation's largest LNG import facility once the renovation and reactivation is complete with a send-out capacity of 1 bcf per day. It was constructed in the mid-1970's at a cost of approximately $400 million.[l] Williams purchased the Cove Point facility in June 2000 from affiliates of Columbia Energy Group. The facility operated from 1978 to 1980, at which time it was closed. In 1995 it was partially reactivated to provide natural gas peaking services.

In October 2001, the U.S. Federal Energy Regulatory Commission (FERC) authorized Williams to reactivate the Cove Point LNG facility and to expand it.[m] Construction began in 2002, with a proposed in-service date for the reactivated facility in the spring of 2003, and a new fifth tank expected to be operational by the 4th quarter of 2004. After expansion, the storage capacity will be 7.8 bcf. The total project is estimated to cost approximately $103 million.

Trinidad and Tobago are expected to be the main supplier of LNG to the facility. The LNG tanker discharging service is fully subscribed under 20-year binding agreements.

In addition to the Cove Point facility, The William Companies own and operate three other LNG facilities in the United States.[n] These facilities are peak-shaving facilities – facilities in which natural gas is liquefied and injected into a storage tank during periods of low natural gas demand, for later vaporization and injection into the pipeline system during high demand periods. These facilities are:

- Transco Station 240: This facility, located in Carlstadt, New Jersey, connects to the Williams Gas Pipeline's Transco system. It has a storage capacity of 2 bcf.

- Pine Needle LNG Facility: This facility, located in Stokesdale, North Carolina, also connects to the Williams Gas Pipeline's Transco system. It has a storage capacity of 4 bcf.
- Northwest Plymouth LNG: This facility, located in Plymouth, Washington, connects to the Williams Gas Pipeline's West system. It has a storage capacity of 2.4 bcf.

Dominion Resources. Note that in September 2002, Dominion Resources, another FRS respondent, bought the Cove Point LNG facility (described above under The Williams Companies) from The Williams Companies in a transaction valued at $217 million.[o]

ChevronTexaco. ChevronTexaco, from the Chevron side of its recent merger, has ownership in two major production ventures in Australia:[p]

- a 16.7-percent ownership share in the North West Shelf (NWS) Project, an area 1,000 miles north of Perth and 70 to 90 miles offshore. About 1 bcf of gas per day in the form of LNG was sold primarily under long-term contract to Japanese utilities. In addition, NWS Partners formed Australia LNG in 1999 to market the LNG. Australia LNG markets uncommitted gas to new Asian markets outside Japan, in particular Korea, China, India and Taiwan.
- a significant, but minority share in the West Australian Petroleum Pty Ltd. (WAPET) operated permit areas.

ChevronTexaco is also evaluating both offshore California and Baja California for one or more LNG import facilities.

From the Texaco side of its recent merger, ChevronTexaco is considering building an offshore LNG receiving terminal off the coast of Louisiana south of the Henry Hub natural gas pipeline interconnection.[q] This location has the advantage of an extensive pipeline grid that is already in-place to deliver the regasified supply. ChevronTexaco is also considering building an LNG plant in Angola, where it has extensive offshore oil and associated gas reserves.

Marathon Oil Corporation. In partnership with Pertamina, Golar LNG Limited, and Gropo GGS, S.A. de C.V., Marathon has developed plans for an LNG marine terminal and re-gasification facility and a 400-megawatt power generation plant near Tijuana in the Mexican State of Baja California.[r] Output capacity would be 1 bcf of natural gas per day, for both local consumption and export, with operation to begin in 2005. The project would supply natural gas and electricity domestically to the Mexican State of Baja California and for export to southern California.

A significant portion of the LNG for the Baja Project is expected to be supplied from the Asia-Pacific region, in particular, by Pertamina, the state-owned oil company of Indonesia.

Phillips Petroleum Company. Phillips Petroleum is the operator and a 70-percent majority owner of the only LNG export facility in the United States, located at Port Nikiski on the Kenai Peninsula in southern Alaska.[s] Phillips built this 230-mmcf-per-day export facility in a joint venture with Marathon, which owns a 30-percent share of the facility.[t] Export began in 1969, under a 15-year contract to supply LNG to Tokyo Electric and Tokyo Gas. Shipping to those two utilities has continued since then uninterrupted. As part of the venture, Marathon pioneered the development of the world's first ocean tankers specially designed to transport LNG.[u] The Kenai plant initiated the Pacific LNG trade. While Phillips operates the LNG facility itself, Marathon coordinates shipping to the Japanese utilities on behalf of the joint venture.[v] In this role, Marathon delivered over 78 bcf of natural gas to Asia in 2001.[w] Phillips developed the (self-named) Phillips' Optimized Cascade LNG Process for liquefaction, first used in the Kenai LNG facility.[x] Phillips licenses its proprietary LNG manufacturing technology to other users worldwide, with current capacity in place of approximately 400 bcf per year.

Phillips also is a partner in a number of other LNG projects. Their participation in the Baja California, Mexico project has already been described in the El Paso section of this special topic. Other such partnerships include:

- Timor Sea LNG to Japan: Under the name of its subsidiary, Darwin LNG Pty Ltd and other Australian affiliates, Phillips has signed an agreement to develop the Bayu-Undan project in the Timor Sea.[y] The Bayu-Undan field contains estimated reserves of 3.4 trillion cubic feet of natural gas. The field is about 500 kilometers northwest of Darwin, Australia, and 250 kilometers south of Suai, East Timor. In an agreement with the Tokyo Electric Power Company and Tokyo Gas Company, 130 bcf per year of LNG would be supplied over a 17-year period. The first delivery is scheduled for January 2006. As part of the project, Phillips would build an LNG facility at Wickham Point near Darwin, Australia. The full cost of developing the Bayu-Undan, building the associated pipelines and the LNG plant, is estimated at approximately $3 billion. Phillips is operator of the Bayu-Undan project, with a controlling interest of 58.6 percent (after a planned sale of a 10.08-percent interest in the Bayu-Undan field to Tokyo Electric Power and Tokyo Gas). Kerr-McGee Corporation, another FRS company, is among the other participants in this project, with an interest of 11.2 percent. The project requires approval from the Australian Government.

  Nigerian LNG: Phillips' subsidiary Phillips Oil Company (Nigeria) Limited, entered into an agreement in September 2001 (in partnership with the Nigerian National Petroleum Company, and the Nigerian Agip Oil Company) to develop a new offshore LNG facility in Nigeria.[z] This preliminary agreement establishes a study team to evaluate the project. If initiated and completed, the facility would have a capacity of 240 bcf per year, and be located offshore in the Niger Delta near the existing Brass River crude terminal. Onshore oil and gas fields, already operated by an existing joint venture among the same companies would supply the natural gas.

Exxon Mobil. Exxon Mobil Corporation, through its subsidiaries, has had a presence in Qatar since 1935.[aa] The company has a 25-percent interest in the RasGas joint venture in Qatar, with production capacity of 290 bcf per year.[bb] Exxon Mobil also has 10-percent interest in Qatargas LNG facilities, which sold over 6 million tons of LNG in 2000.

In addition, Exxon Mobil, with a 30-percent interest in joint venture with Qatar Petroleum (70 percent), in 2001 entered into a sales agreement with Petronet Ltd. of India to supply LNG for 25 years, with 240 bcf per year to be delivered beginning in 2003 to an import terminal at Dahej, Gujarat State, that is currently under construction.[cc]

BP.[dd] Trinidad and Tobago**:** A subsidiary of BP, BP Trinidad and Tobago Company (formerly Amoco Trinidad), is the largest shareholder (at a 34-percent interest) of Atlantic LNG Company of Trinidad and Tobago, which was formed in July of 1995.[ee] Atlantic LNG built an LNG facility in Point Fortin in Trinidad and Tobago, which began operation in 1999. In that year, Atlantic exported 51 billion cubic feet of natural gas to the United States and 25 billion cubic feet to Spain.

BP supplies all of the natural gas for Train I of the Atlantic LNG project. This facility is currently being expanded with the addition of two additional trains currently under construction at a cost of $1.1 billion, which will add 3.3 million metric tons per year each by late 2003.[ff] This expansion will triple Atlantic's LNG export capacity.

China: China is planning an LNG import terminal in Guangdong province, which, in 2001, BP won the right to build though not necessarily supply.[gg] If it were to earn supply rights, BP Amoco would likely turn to the Tangguh project in Irian Jaya, Indonesia for supply.

Basque Region of Spain: In 2000, BP Amoco initiated a project scheduled for completion in 2003, to put an LNG plant in the port of Bilbao in Spain's Basque region, along with a companion 1200 megawatts power plant which would use the LNG. BP has a 25-percent share in this project, called Bahia de Bizkaia, along with its partners Repsol-YPF, Iberdrola, and the Basque energy authority Eve. The project's regasification plant is slated to have a capacity of 95 billion cubic feet per year.[hh]

What Might the Future Hold for LNG?

According to the Energy Information Administration's (EIA's) *Annual Energy Outlook 2003,* demand for natural gas is slated to increase over the long haul, as are natural gas prices. Therefore, it is likely there will be strong incentives to find and produce more natural gas in the future.

As existing natural gas reserves get depleted, producers will need to turn to new sources, including natural gas in more remote areas. Many areas with natural gas lack the necessary infrastructure for local consumption of the resource: a pipeline grid and energy users with natural gas-fired technologies for residential heating, power production, and the like. Such areas with limited potential for local use for the natural gas are candidates to be sources of LNG in the future.

The expectation of rising natural gas prices, along with the potential continued decline in the costs in the LNG supply chain -- liquifying the natural gas, transporting it in the form of LNG, and regasifying -- makes LNG appear likely to grow in the future.[ii] For more information on possible future LNG scenarios, see the EIA service report entitled *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply* (available on the Internet at http://www.eia.doe.gov/oiaf/servicerpt/natgas/index.html).

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[b] See "LNG Costs and Markets Have Changed in Recent Years," Petroleum News Alaska, March 28, 2001, P.1. Web address: http://www.petroleumnewsalaska.com/pnarch/010328-25.html.
[c]Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), p. 3. Web address: http://www.eia.doe.gov/oiaf/aeo/index.html (as of November 19, 2002).
[d]El Paso Corporation, May 2002 discussion on "El Paso Global LNG." Web address: http://www.epenergy.com/portfolio/lng.asp.
[e]El Paso Corporation, Press Release (September 10, 2001).
[f] El Paso Corporation, November 2002 discussion on "Planning for Tomorrow's Capacity." Web address: http://www.epenergy.com/portfolio/lng_future.asp. Also, Phillips Petroleum Company, Press Release (March 8, 2001).
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[p]ChevronTexaco Corporation, November 2002 discussion on "Worldwide Upstream." Web address: http://www.chevron.com/about/annual%2Dsupplement/p12.html.
[q]ChevronTexaco Corporation, Press Release (May 15, 2001). Also *LNG Express* (May 24, 2001). Web address: http://www.lngexpress.com/lng2001/pressrelease.asp.
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[s]Phillips Petroleum Company, Press Release (September 14, 2000).
[t]Marathon Oil Corporation, Press Release (February 28, 2002). Also, Marathon Oil Corporation, November 2002 discussion on "Integrated Natural Gas." Web address: http://www.marathon.com/our_business/marathon_oil_company/integrated_natural_gas/default.htm.
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